TOWARDS A CONTINENTAL NATURAL GAS MARKET: HISTORICAL PERSPECTIVES AND LONG-TERM OUTLOOK

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PREFACE

This study was initiated in February 1987 and completed in January 1988. Most of the data assembly and modelling work was completed during the period from April to October of 1986. A separate Executive Summary covering the important results and conclusions of the study is also available from the Institute.

The study was made possible by the collaborative effort of a number of organizations and individuals. Dr. Gordon Sparks, a professor at the University of Saskatchewan, played a major role in initiating the study by alerting CERI that the GRI North American Regional Natural Gas Model was available for such a purpose. The United States Gas Research Institute--the principal users of the model--granted CERI permission to use valuable GRI data in the modelling work. Decision Focus Inc. (DFI) of Palo Alto, California--the developers of the model--granted CERI access to the model software. Rod Rinholme, a graduate student of Dr. Sparks and now an employee of GRI, completed the initial modelling work which was subsequently finalized with the assistance of Dale Nesbitt and Jagjot Singh of DFI. Gerald Pine of GRI provided ongoing support and valuable advice throughout this period. Readers who wish to contact any of these individuals for further elaboration on the model software or data can do so through CERI.

The author would also like to express his gratitude and that of the Institute to the six-member Advisory Committee of industry representatives for the direction, insights, and constructive criticism provided for this study. The views and conclusions expressed herein are, however, those of the author, who accepts sole responsibility for any errors or omissions that may exist.

Special thanks must be extended to various members of the Institute's staff for their efforts in putting together the finished study. Graphics work was performed by Vance Lickiss and the final manuscript and many drafts were typed by Janice Morrison and Michele Irvin. Finally, Tony Reinsch provided support and guidance throughout the project as well as editing and reviewing the study.

PART I

Chapter 1

INTRODUCTION

The last decade has witnessed a dramatic transition in Canadian and U.S. natural gas markets. Both countries have moved away from rigidly structured systems characterized by regulated prices and pipeline rates, inflexible contracting practices, and government intervention at all levels of the market. In today's gas markets, although pipeline rates remain regulated (and will likely remain so in the future), gas prices are no longer regulated and are determined in the marketplace through negotiation between buyer and seller. Fundamental market forces are being allowed to reassert themselves and gas is now competing vigorously against itself and alternative fuels in all end-use markets. Producers, transporters, and distributors in Canada and the U.S. are faced with the challenge of selling natural gas rather than simply delivering it, as was the case in the previous market environment.

In a world of falling energy prices, market-based pricing is essential if gas is to efficiently meet the very real competitive pressures of today's markets and sustain or increase current levels of demand in the future. Deregulated pricing will provide gas markets with the flexibility required to meet interfuel competition to the extent that underlying gas supplies permit. Although the certainty of regulatory decisions will be gone in this new environment, participants will have more control over their own fates. Unfortunately, these fates will depend on market forces such as fluctuating oil prices that are highly uncertain. It is likely, however, that the market will prove to be much more effective at assigning risks and determining prices than any regulatory or government organization.

Canadians can expect these changes to ultimately have a profound impact on gas trade with the U.S. Export prices are no longer prescribed by government and essentially have only to meet an after-the-fact criteria that they not remain below domestic prices for a sustained period of time. The export surplus rule has been modified by the National Energy Board (NEB) to achieve some consistency with price deregulation. The new "Market Based Procedure" no longer relies on a formulaic approach to determining Canada's exportable surplus.

Instead, a public hearing and monitoring process will be utilized to ensure that Canadian users can contract for gas under similar terms to those being offered in the export proposal and that the export is in the Canadian public interest.

These decisions by Canadian authorities have engendered considerable momentum for the creation of a continental gas market. The recent Free Trade Agreement between Canada and the U.S., if ratified, will reinforce this movement towards a unified North American gas market. Today, and increasingly in the future, Canadian gas will have to compete with U.S. gas and alternative fuels on a regional basis. The key variables that are likely to emerge in this process will be the relative transportation costs between Canadian and U.S. gas supplies, the underlying supply costs of competing gas sources, the distribution of undiscovered gas resources relative to the existing pipeline network, and the price of fuel oil in that market. Moreover, prices in Canadian markets will be influenced by conditions in U.S. markets to the extent that netbacks from export sales feed back into the Canadian wellhead and flow back to the various Canadian burner-tip markets.

Unfortunately, this evolution towards a "freer" market has been impeded by the inertia of decades of regulation. The current surplus in productive capacity in both countries is a direct result of the distortionary impact which non-market prices, and the export surplus test in Canada, have had on the producing sector. Moreover, because natural gas deregulation occurred in a period of excess gas supplies, there has been a pronounced downward movement in prices and a corresponding loss in producer and royalty revenue because expected sales growth has not yet materialized. Current wellhead prices appear to be below replacement costs and are thus intrinsically not sustainable for an extended period of time.

Inflexible contracting practices that evolved in a regulated market have slowed the deregulatory timetable, particularly in the U.S. Interstate pipelines that entered into high priced contracts with very stringent take-or-pay provisions in the early 1980s now find themselves in a position where they are liable for up to $6.8 billion (U.S.) in combined take-or-pay exposure.[1] These take-or-pay liabilities have been a primary factor in the difficulties the U.S. industry has encountered in effectively opening up their pipeline system. An operative resolution of this problem and implementation of open access transportation is essential if Canadians are to efficiently compete in U.S. markets.

While Canadians have been considerably more effective in implementing open access transportation on domestic pipelines, several important issues have yet to be resolved. Perhaps the most important of these is the right of the core market to participate in the direct sales market.[2] The current availability of inexpensive gas on the direct sales market has created considerable incentive for core customers to leave system sales despite downward price adjustments in existing contracts between local distribution companies (LDCs) and Western Gas Marketing.[3] Since these contracts do not generally expire until the mid-1990s and must be honored by the various LDCs under the NEB's self-displacement proviso, they are effectively precluded from entering the direct sales market to lower gas purchase costs for their core customers. Moreover, the Alberta Government has been reluctant to issue the requisite removal permits to allow direct sales to core customer groups, such as municipalities, which have the resources to arrange their own gas supplies.

No transition process, however, can expect to be entirely smooth, especially in the case of the momentous change currently encompassing the North American gas industry. Participants at all stages in the supply system are being forced to develop new marketing and contracting techniques to deal with situations that never arose in a regulated market. Given this and the precipitous decline in gas prices over the past few years, it is not surprising to see the industry preoccupied with present conditions. These conditions are, however, subject to the twists and turns that accompany any transition period and may obscure long-term trends that have important strategic implications for all segments of the industry. This study deals not only with the transition phase but also looks beyond current conditions to understand how future markets might evolve.

1.1 Study Objectives and Goals

The objectives of this study are twofold. First, given the complexity of the gas industry and the relative newness of deregulation to Canadians, we wish to provide an educational component which:

- reviews the market forces providing impetus for deregulation in Canada and the U.S.;
- discusses the deregulatory initiatives taken to date in both countries, problems that are being encountered in

their implementation, and their impact on the marketplace; and

- describes the basic structure of the gas industry from a supply-demand perspective.

This aspect of the study should provide those readers having little background in the industry with a useful reference on the essential composition of the North American natural gas market. It also serves as a valuable starting point towards a more in-depth understanding of how gas markets operate and of the fundamental issues affecting market development.

Second, the study is intended to fill a perceived need for a long-term appraisal of the future development prospects for the Canadian gas industry within the increasingly integrated North American gas market. In a natural resource industry that is characterized by long lead times between discovery and development of new reserves and the addition of pipeline capacity, market participants must not only have a thorough understanding of the current state of the gas industry, but also a view as to how the market is going to evolve in the future. Some important long-term issues that face the Canadian gas industry which we address in this study include:

- future gas prices in domestic and U.S. markets;
- the identification of future export markets--both locationally and volumetrically;
- the need for new or expanded pipeline facilities to serve new or incremental export and/or domestic markets;
- the adequacy of conventional gas supplies to meet future demand; and
- concomitantly, the timing of unconventional and frontier gas production to augment these supplies.

Given the vast scope and complexity of North America's gas industry, a comprehensive long-term market analysis tool that is based on a descriptive and theoretically respectable methodology is required to examine such issues. This component of the study is based on such an analytical tool, known as the GRI North American Regional Natural Gas Model.

The regional gas model was orginally developed by Decision Focus Inc. (DFI) under the sponsorship of the Gas Research Institute

(GRI) in the United States, as a planning tool to quantify the benefits likely to accrue from GRI's research programs. An invaluable aspect of this model is the detailed regional data base which is used to describe natural gas supply, demand, and transportation in the U.S. Both organizations have committed substantial financial and human resources towards the construction of this data base. Given the likelihood that future Canadian and U.S. gas markets will become increasingly integrated, this is a prerequisite to accurately analyzing future natural gas exports. A requisite task of CERI in utilizing the model was the review and further enhancement of the data base describing the Canadian component of the model.

The results of the modelling work presented in this study are intended to aid Canadian resource managers and government and regulatory organizations in their strategic planning process. A secondary objective is the introduction of this modelling methodology to participants in the Canadian gas industry to whom the model has generally been inaccessible until now. It is hoped that the results of this study will stimulate further interest in the model as a useful strategic forecasting tool for analyzing the future development of the Canadian gas industry. Any additional refinement and enhancement of the modelling framework that results from such interest will further contribute to all parties' understanding and expectations of future gas markets.

1.2 Study Structure

In satisfying the goals and objectives of this study as described above, a considerable amount of material has been included that may be quite familiar to those readers who are intimately involved in the gas industry. The study has been structured so that these readers will lose little in continuity if they read around Chapters 2 through 4 and focus on Chapters 5 through 8. Part I of the study, Chapters 2 through 4, essentially provides a historical overview of the gas industry and lays the foundations for the supply/demand framework used in the model analysis. Part II, Chapters 5 through 8, describes some important elements of Canada/U.S. gas trade, the modelling framework and underlying data, the model results and the implications and recommendations we draw from the analysis. A brief summary of the content of each of the chapters is provided below.

Chapter 2 provides a description of the past and current natural gas markets in Canada and the U.S. The first section is a historical overview which focuses on market forces that emerged in the

1970s and that provided impetus for deregulation of the Canadian and U.S. gas industries. The second section describes these deregulatory initiatives and some of the problems that have been encountered in attempting to implement them. The final section examines some key features of the current market and their impact on market structure, prices, and contracting practices.

Chapter 3 discusses the supply of gas in Canada and the U.S. The first section of the chapter provides a description of the existing pipeline network and current transportation costs as well as a discussion of the exploration and development process, outlining some key variables affecting costs. Because the regional gas model requires a careful specification of the full spectrum of possible future gas supplies, the ultimate potential and costs of conventional gas supplies as well as frontier and nonconventional gas supplies in North America are examined. This requires a discussion of historical supply costs and indicators of future cost trends such as field sizes and finding rates. Salient statistics on reserves, production, and other key indicators of natural gas supply are also presented and discussed.

Natural gas demand in North America is discussed in Chapter 4. This chapter provides an overview of the principal determinants and special characteristics of natural gas demand in the various end-use sectors, a review of historical gas consumption patterns and a forecast of future natural gas demand. Both historical and future gas demand are examined on a sectoral and regional basis to maintain consistency with the disaggregation employed in the regional gas model.

Chapter 5 provides a perspective on natural gas trade within North America. Past Canadian trade with the U.S. is discussed as well as recent trends in the export market, current market barriers and the impact that regulatory changes and a possible Free Trade Agreement might have on future natural gas trade. The potential shortfall in U.S. gas requirements and the implications this holds for future Canadian exports is then examined by providing a survey of export forecasts formulated by GRI and other organizations. Finally, the issues raised by these forcasts are briefly examined.

A description of the North American Regional Natural Gas model is contained in Chapter 6. This discussion focuses on the Generalized Equilibrium Modelling System (GEMS), upon which the gas model is based, the application of this methodology to the gas industry and the regional structure of the gas model. In addition, the data on natural gas supply, demand and transportation costs presented in Chapters 3 and 4 are consolidated and presented in the form in which they are used in the modelling framework.

Chapter 7 presents our long-range forecast and analysis of natural gas prices and quantities as calculated by the regional gas model. Detailed results for a reference case are provided first. These results include:

- burner-tip prices by sector and region in Canada;
- average wellhead prices and production by region in Canada;
- required reserves additions to support the above levels of production;
- natural gas exports and delivered price by U.S. demand region;
- prices and quantities delivered by competing sources into the U.S. demand regions; and
- average wellhead prices and production by region and technology in the U.S.

The impact of key sensitivities and policy alternatives on the reference case forecast are then presented and evaluated. The chapter concludes with a discussion of the implications these results hold for the Canadian gas industry.

Finally, Chapter 8 provides a summary of the essential results of the study as they pertain to the future development of the Canadian gas industry. A number of recommendations as warranted by the research work are put forward and some areas for future research that show considerable promise for enhancing the quality of the modelling methodology and associated forecast are suggested.

A number of appendices are also included in the study. Appendix A provides some useful conversion factors and common units used throughout the gas industry. Appendix B provides a glossary of often used terms to aid the uninitiated reader in deciphering some of the jargon particular to the gas industry. A chronology of regulatory developments in the Canadian and U.S. gas industries is contained in Appendix C. Two elements on natural gas supply which are discussed in

Chapter 3 are expanded upon in Appendices D and E. Appendix F contains a brief discussion and presentation of salient statistics on selected U.S. local distribution companies having access to Canadian gas. A more in-depth and technical discussion of the modelling methodology appears in Appendix G. Finally, Appendix H presents a detailed tabular coverage of the model results for every case examined in Chapter 7.

Footnotes

[1] This estimate was reported in Natural Gas Week, vol. 3, no. 36, September 7, 1987, p. 1 and is taken from a study released by the Interstate Natural Gas Association of America.

[2] We note here that there generally is not a widely accepted definition of what actually constitutes the core market. The Pipeline Review Panel did tentatively define the core market as those customers who require both a secure supply of gas and a transportation service from a distributor and are effectively dependent upon the distributor for such a supply and service. This issue of core market participation in the direct sale market is discussed in more detail in Chapter 3.

[3] We refer to the contracts between LDCs and Western Gas Marketing because this is where most attention is focussed. However, the same general situation applies to contracts between Westcoast Transmission and British Columbia LDCs.

Chapter 2

TODAY'S NATURAL GAS MARKET

2.1 Introduction

The 1980s have proven to be a dynamic decade for all sectors of the natural gas industry, with more change in store as we draw closer to the 1990s. Underlying this change has been a pronounced reversal by governments in both the U.S. and Canada (albeit several years behind the U.S.) regarding their philosophy of the market environment most conducive to efficient utilization of the gas resources of the two countries. This reversal in philosophy has manifested itself in a movement away from a market in which both gas prices and pipeline rates were determined by either government or regulatory agencies towards one in which only pipeline rates will remain regulated. Prices at the wellhead and at the U.S. border will be deregulated and their level determined by negotiation between buyer and seller. The resulting market price will thus reflect both parties' perception and knowledge of the current and expected demand-supply situation and the current and expected prices of alternative fuels.

Unfortunately, this evolution towards a "freer" market has been impeded by the inertia of decades of regulation. The current surplus in productive capacity in both the U.S and Canada is a direct result of the distortionary impact which non-market prices, and the export surplus test in Canada, have had on the natural gas production sector. Contracting practices that evolved in a regulated and expanding gas industry have exacerbated the situation and considerably slowed the deregulatory timetable in the U.S. So pernicious were these practices that when demand for natural gas was falling in the U.S. in the early 1980s, gas prices to the end-user were actually increasing.[1] U.S. interstate pipelines now find themselves in a position where, because of contractual obligations, they are liable for up to $6.8 billion (U.S.) in take-or-pay exposure.[2] These take-or-pay liabilities have also been a primary factor in the difficulties the U.S. industry has encountered in attempting to "open up" their pipeline system to allow access to end-users of inexpensive surplus gas.

This chapter is intended to provide an overview of the past and current natural gas market. The first section examines the market forces that emerged in the 1970s and that provided the impetus for the deregulation initiatives in place today. The second section briefly discusses these initiatives and some of the problems that have been encountered in attempting to implement them. The final section examines some key features of the current market and their impact on market structure, prices and contracting practices.

2.2 Towards Deregulation

It was not possible for the natural gas industry to become a reality until the requisite gathering, long distance transportation and distribution facilities were constructed. In the U.S. the first long distance pipelines were constructed in the 1920s connecting the gas fields of the Appalachians and West Texas with major industrial centers. By 1960, over 630,000 miles of pipeline had been installed in the U.S. By 1984, this total had nearly doubled to 1,102,245 miles and over 30 interstate pipelines were connecting the major supply regions with end users in all regions of the U.S.[3]

By the early 1950s it had become apparent that substantial reserves of natural gas were present in Alberta and the northeast part of B.C. and that in order to realize the potential value of these resources, pipeline facilities to distant markets in Canada and the U.S. were required. In 1957, two natural gas trunk pipelines began operations in Canada. Westcoast Transmission operated a pipeline to Vancouver which was subsequently extended to the U.S. border, connecting it to Northwest Pipeline Corp. which serves the Seattle, Washington, and Portland, Oregon areas. TransCanada Pipelines Limited (TCPL) began transporting gas to Central Canada and the United States. During the same period, the Alberta government established Alberta Gas Trunkline (now NOVA) to transport gas from various fields within the province to points of removal from the province. In 1961, Alberta Natural Gas Co. (ANG) completed a pipeline from the Alberta border to Kingsgate, B.C. to export Alberta gas to the Northern California market via Pacific Gas Transmission (PGT).

Once the enormous capital investment for these facilities was made and construction completed, the stage was set for a period of sustained growth in the Canadian natural gas industry. Total domestic sales of natural gas increased from 390.1 PJ (370 Bcf) in 1962 to 1628 PJ (1547 Bcf) in 1983 while export sales increased from 426 PJ

(405 Bcf) in 1965 to 1081.4 PJ (1027 Bcf) in 1973 and 1060 PJ (1007 Bcf) in 1979.[4] The U.S. industry underwent a similar expansion after the Second World War with total consumption increasing from 3.85 Tcf in 1946 to a peak of 22.1 Tcf in 1973.[5]

Within this setting of constant expansion, institutional and regulatory arrangements evolved that reflected the need for security of supply to finance transportation facilities and new market penetration, and that ensured reliable service to all customers at a fair price. While the institutional features of gas markets in the two countries were quite similar, sharp contrasts emerged in the regulatory environment maintained in each. With the passage of the Natural Gas Act (NGA) in 1938 in the U.S., responsibility for the regulation of interstate pipelines (those pipelines that crossed state borders) was passed on to the Federal Power Commission (FPC, later renamed the Federal Energy Regulatory Commission, or FERC). The essential features of FPC pipeline regulation were "certification" of facilities and a "tariff" governing rates and obligations to serve. The NGA, however, was ambiguous with regard to the regulation of wellhead prices. Rising prices in the late 1940s and early 1950s resulted in a Supreme Court decision (known as the Phillip's Decision) in 1954 granting the FPC the right to regulate prices at the wellhead. Price ceilings were established at this time, based on historical production costs.

Price regulation did not formally appear in Canada until 1975 under the terms of the Natural Gas Pricing Agreement between the Alberta and Federal Governments. However, from the outset natural gas destined for export was subject to quantity regulation in the form of a surplus test. The Alberta Oil and Gas Conservation Board (later renamed the Alberta Energy Resources Conservation Board, or AERCB) under the auspices of the Gas Resources Preservation Act of 1949, initially determined that the removal of additional volumes of gas from the province was in the public interest only to the extent that established reserves exceeded 30 years of estimated future domestic consumption plus any already authorized exports.

The National Energy Board (NEB) was established in 1959 and, among other responsibilities, was charged with the setting of pipeline tariffs, the certification of pipeline facilities and the power to approve gas exports subject to the provision that they be surplus to reasonable Canadian requirements. In discharging the latter responsibility, the NEB adopted a procedure similar to that of the AERCB. As confidence increased about the likely volume of future supplies, both the NEB and AERCB gradually relaxed their surplus requirements. As of 1983, the AERCB and NEB had reduced the surplus reserve requirements to the equivalent of about 25 times domestic requirements in the first year of the contract (provincial requirements for the AERCB and national requirements for the NEB) plus previously authorized exports. Both parties utilized some form of deliverability criteria to assess whether annual requirements could be met in the future.[6]

Concern about the low level of field prices being obtained by domestic producers as the result of buyer-seller negotiation caused the Alberta Government to legislate the basis for determining gas prices in arbitration proceedings. This, combined with the OPEC price shock in the early 1970s, gave rise in 1975 to the Natural Gas Pricing Agreement which established an interprovincial price for gas of $1.25 per Mcf at the Toronto City Gate. Under the agreement this price, approximately 85 percent of the Btu equivalent of crude oil, was to be increased by the Federal Government so that within 3 to 5 years domestic prices would reach 100 percent Btu-parity with oil prices.[7] This principle of tying the domestic natural gas price to crude oil prices continued under the National Energy Program (NEP), established in 1980 in the wake of the second OPEC price shock. Premised on expectations of ever increasing oil prices, the NEP, among other goals, sought to facilitate the substitution of natural gas for oil by reducing the city gate price of gas relative to oil to 65 percent of the Btu-parity.[8] This ratio was maintained in the 1981 Energy Agreements between the Federal Government and the governments of the producing provinces which sought to resolve the controversy resulting from the Federal Government's unilateral imposition of the NEP.

Prior to 1976, Canadian export prices were set with regard to competing fuels in particular regions and the price thus varied somewhat from region to region. In response to a 1976 NEB proposal to further increase export prices based on conditions in each export market, the U.S. proposed the concept of a uniform border price to avoid discrimination between states. Under the uniform border price policy, export prices were determined by the price of imported crude oil to Eastern Canada. The second oil price shock in 1979 caused Canadian export prices to increase from $1.90 (U.S.) per Mcf at the beginning of 1979 to $4.94 (U.S.) per Mcf in April 1981.

A number of institutional features emerged within this environment of expansion and regulation. Pipeline companies purchased production from gas producers, transported the gas at a cost determined through tariff regulation to local distribution companies (LDCs), who delivered it to end-users, also at a cost determined by cost of service regulation. Contracts between pipelines and producers were generally long-term arrangements--10 to 20 years--and typically contained take-or-pay clauses which required pipelines to pre-pay producers for minimum volumes even if less was actually taken. These clauses were more or less matched by minimum bill provisions in pipeline-distributor contracts which required the LDC to pay a set fee over and above a demand charge, whether or not the LDC took delivery of contracted gas. Such contractual provisions were necessary to finance required transportation facilities, as they could not otherwise be leveraged with lower cost financing because of the higher risk of alternative gas supply arrangements. Moreover, these arrangements induced considerable stability to the market while distributing the obligation to serve from wellhead to burner-tip, and provided producers with a stable cash flow to enable them to obtain financing for expenditures on gas exploration and development.

The wellhead price ceilings imposed by the FPC in the U.S. in the aftermath of the Phillip's Decision soon became binding because they were based on historical production costs while producers were having to access new higher cost reserves. As the ceilings only applied to the interstate market, an intrastate market free of such controls developed and prospered in the producing states. With market clearing intrastate prices exceeding the price ceilings in the interstate market, interstate pipelines were unable to compete for reserves. Shortages began to appear in certain interstate markets in the late 1960s and early 1970s, forcing the FPC to develop an elaborate set of curtailment procedures. In this atmosphere of shortage, pipelines had no difficulty selling their available gas and were legally protected against failure to deliver by FPC curtailments. During this period many industrial users installed dual fuel capable equipment to burn residual fuel oil, for reasons of supply security rather than cost.

Such shortages soon became politically intolerable, causing the U.S. Congress to legislate the passage of the Natural Gas Policy Act (NGPA) in 1978 in an attempt to remedy the situation. The NGPA was intended to eliminate the division between intrastate and interstate markets and to allow gas prices to rise to market clearing levels. The complex act established 24 categories of gas and price ceilings for each. A major feature was the distinction between old gas, which was to be forever regulated at low prices, and new gas which was essentially deregulated.

Because of the perceived shortages, competition for new reserves was very intense following the passage of the NPGA. As price ceilings in some instances were still below market clearing prices, gas producers won very favourable contract terms in the negotiation process, such as price escalator clauses assuring them of the highest available price and very stringent take-or-pay obligations--in the order of 80 to 90 percent of contracted volumes versus the traditional range of 50 to 60 percent. Moreover, in this period, few pipelines had the foresight or the negotiating leverage to obtain "market-out" rights in their contracts--that is, the right to reduce prices unilaterally if they could not clear the market. Thus in 1981, interstate pipelines held portfolios of gas contracts comprised of old gas priced at $1.00 - $1.50 per Mcf, "new" and "stripper-well" gas priced at $2.25 - $3.00 per Mcf and rising steadily, and high priced gas (mainly "deep" gas and imports) priced at $4.00 - $11.00 per Mcf.[9] Nationally, somewhat more than half of the interstate portfolio was old gas, just over a third was new gas and the remainder was high priced gas. The pipelines rolled these price categories together to get a simple, weighted average cost of gas.

In Canada, there was no problem contracting for reserves and, in fact, by the late 1970s there was growing evidence of a deliverability surplus. This development was in sharp contrast to the prevailing mood of the early 1970s. With growing market demand throughout the 1960s and most of the 1970s, most forecasts, including those of the NEB, were predicting that Canada was facing an impending natural gas shortage.[10] In light of these circumstances and related price increases, between 1974 and 1976 Western Canadian producers aggressively explored and TCPL aggressively contracted for new Alberta gas reserves. As in the U.S., Alberta producers were able to win favourable contractual terms in the negotiation process at the expense of increasing the rigidity of the contract structure. These included an increase in TCPL's minimum take obligations and area-based contracts which allowed producers to include additional volumes found within a specified geographic area in the volumes covered in the gas purchase contract.

While such contractual provisions and higher prices induced a rapid build-up in productive capacity, at the same time higher prices were stimulating consumer conservation and resulted in flat domestic and export demand rather than the rapid growth that TCPL had anticipated (especially in the export market). As a result, TCPL volume takes fell significantly below full contract levels and the company was forced to introduce a prorationing scheme in April 1978 to ensure that the available market was equitably shared among its suppliers.

Because of its low rates of take from producers, even with this mechanism in place TCPL soon encountered serious financial difficulties with its take-or-pay provisions. From 1977 through 1981, TCPL paid for but did not take, 607 Bcf of contracted gas for a total take-or-pay obligation of $1.013 billion. It soon became evident that TCPL could not continue borrowing on its own account to fulfill its take-or-pay obligations with producers.

In 1982, the TOPGAS I (Take-or-Pay Gas) program was established. Under the program, a consortium of financial institutions agreed to take over the $1 billion TCPL debt and producer liability for pre-paid gas for the years 1977 to 1980, and to loan producers $1.3 billion in place of TCPL's take-or-pay obligation incurred in the 1980-1981 and 1981-1982 contract years. In return for the advance, producers agreed to reduce the take-or-pay threshold from 80 percent to 60 percent of contracted volumes. TCPL's sales continued to stagnate in the following year and it was unable to fulfill its minimum obligations under TOPGAS I. This resulted in the formation of the TOPGAS II agreement under which a second consortium of banks advanced producers a further $320 million for gas not taken in the 1982-1983 contract year. Producers in turn agreed to a further reduction in TCPL's minimum take obligation to 50 percent of contracted levels. Recovery of the TOPGAS principal takes place out of producer revenues during the five winter months (November to March) over a 10-year period.[11] The carrying costs of the loans are recovered from producers through a TOPGAS charge levied at the Alberta border.[12]

The economic recession of 1981 to 1983, in concert with falling oil prices, increasing gas prices and vigorous conservation initiatives in both Canada and the U.S., abruptly ended the era of growth in the natural gas industry. Natural gas consumption in the U.S. fell by 3.4 Tcf between 1979 and 1983 mainly in the industrial and electricity generation sectors, as users switched to lower cost residual fuel oil.[13] Although Canadian consumption remained flat at about 1.5 Tcf, exports to the U.S. fell from 1007 Bcf in 1979 to 712 Bcf in 1983.[14]

Unfortunately, this reversal in demand was not forseen by the major players in the industry and the pricing and allocation mechanisms were entirely too rigid to allow the system to respond by lowering prices. In fact, in the U.S. the contractual position of interstate pipelines--take-or-pay provisions on high cost contracts forced many pipelines to take higher cost gas rather than lower cost gas to minimize take-or-pay liabilities--and the perverse influence of lower volumes on transportation costs combined to increase prices through this period.[15] The average price paid by the U.S. consumer increased from $2.34 (U.S.) per Mcf in 1979 to $4.82 (U.S.) in 1983 while Canadian export prices climbed to a peak of $4.94 (U.S.) per MMBtu in 1981 in the face of declining sales.[16] Domestic natural gas prices remained more or less tied to the price of crude oil under the NEP through August 1984, although some industry specific discounts were being developed.

At the same time, higher wellhead prices for gas and favourable contractual provisions were stimulating drilling activity and resulting in increased gas supplies in both countries. In Canada, the gap between actual production and productive capacity widened from about 0.95 Tcf in 1979 to 2.25 Tcf in 1983, while in the U.S. the gap widened from essentially zero in 1979 to 4.5 Tcf in 1983.[17] While these aggregate statistics mask interesting differences in drilling patterns and reserves additions in the two countries (these are discussed in Chapter 3), they serve to illustrate the magnitude of the producer response to changes in price.

By the end of 1983 it had become apparent that the institutional and regulatory environment within which the natural gas industry operated was too rigid to deal with the new realities of:

- significant interfuel competition in the industrial and electric utilities sectors; and
- surplus productive capacity in the production sector of the industry.

While the traditional modes of marketing--purchase by pipelines at the wellhead for resale to LDCs at the city gate--and the corresponding contractual arrangements--long-term contracts between pipelines and producers with some sort of take-or-pay provisions, and minimum bill requirements in similar length contracts between pipelines and LDCs-had fostered stability in a growing industry, and indeed were probably necessary to induce this type of growth, they had proven incapable of dealing with these new realities. A more flexible system was required to deal with such problems as:

- how to get cheaper natural gas to the more price sensitive industrial market where competing fuels, mostly crude oil based, had made significant inroads on the market share of natural gas;

- how to allow producers with low cost shut-in and surplus gas access to these incremental markets;

- in Canada, how to restore export volumes to near contracted levels and realize the potential opportunities this market might offer in the future; and

- how to implement the above and prevent natural monopolies such as the trunk pipelines and LDCs from taking advantage of their inherent market power.

2.3 "Freer" Market Initiatives

Natural gas "decontrol" or "deregulation" are generic terms commonly used to describe the efforts made in Canada and the U.S. to loosen the regulatory framework controlling the gas industry. The underlying philosophy of "deregulation" is that a "freer," more competitive natural gas industry will exhibit the flexibility necessary to deal with the problems discussed above and those that might arise in a highly uncertain future, and that it will do so in a more efficient manner than is possible in a highly regulated system. The deregulatory initiatives taken to date in Canada and the U.S. have illustrated some common elements--most notably, that:

- "open access" on the major trunk pipelines is imperative to achieve a more competitive market environment;

- some additional flexibility in the contracting mechanism is required to (i) remove the distortionary impact that price and volume terms in existing contracts are having on achievement of the above and on the ability of end-users to obtain competitively priced alternative supplies, and (ii) allow prices in the future to more readily respond to changing market conditions; and

- prices should no longer be regulated but rather be determined solely through negotiation between buyer and seller.

2.3.1 The U.S. Experience

The Natural Gas Policy Act (NGPA) of 1978 was the first of a number of initiatives in the U.S. directed towards using the market rather than regulation to determine prices and assure adequacy of natural gas supply. At the heart of the NGPA was Congressional recognition that wellhead prices for interstate sales were too low and that, to induce more drilling and reserves additions, prices had to be tied in some fashion to market value. In addition to setting higher prices, the Act provided for total wellhead decontrol for most "new" gas effective January 1, 1985 and certain other categories by July 1, 1987. "Old" gas, however, was to be forever regulated at below market clearing prices to prevent price fly-ups to the captive sector of the market due to higher price ceilings for newer gas.

By 1983, it was apparent in the U.S. that the NGPA by itself was insufficient to realign markets and had, if anything, introduced new distortions into the market in the form of prices above market clearing levels and surplus productive capacity. As gas prices approached and then exceeded oil prices, the FERC embarked on a series of regulatory reforms to help remedy a severely disordered market. Of particular importance are the following programs and rulemakings that the FERC has attempted to institute since 1983, and which address the need for increased flexibility in existing market arrangements and an effective transportation mechanism.

- Special Market Programs (SMPs). SMPs were introduced in 1983 in an effort to recoup the dual-fired incremental market. In the typical pipeline SMP, gas that was dedicated to system supplies could be released and sold to an end-user that might otherwise be served by an alternate fuel, if the producer was willing to accept the price necessary to lure that end-user back, and if he was willing to credit any such sales to the take-or-pay liabilities of the pipeline. Although SMPs offered a promising first step toward introducing some much needed flexibility into the U.S. system (in that producers and end-users were able to enter into direct sales contracts with the pipeline acting solely as a transporter), they were subsequently ruled illegal in 1985 by the courts because they discriminated against the captive customers of the pipeline who were not able to participate in the program.[18]

- Blanket Transportation Programs. Section 7 of the Natural Gas Act requires that a certificate be obtained from the FERC before gas can be transported in interstate commerce. The procedure for obtaining an individual certificate was expensive and time consuming, and inconsistent with the FERC's desire to increase the flexibility of gas movement. In July 1983, the FERC issued Order No. 234-B and No.

319 effectively extending transportation on a "self-implementing" basis (i.e., without prior specific transportation authorization from the FERC) to all end-users, regardless of end use, without the previous individual certificate delays and expense. As with the SMP program in 1985, the courts rejected the end-user blanket transportation programs on the grounds that they permitted pipelines to limit transportation availability to fuel switching customers, thereby discriminating against the pipelines captive customers, primarily the LDCs.[19]

- Elimination of Gas Costs for Pipeline Minimum Bills. Until 1984, the major cost recovered through the minimum bill was pipeline gas purchase costs or take-or-pay payments. The minimum bill was essentially the covenant by which customers would indemnify the pipeline for incurring costs to obtain long-term gas supplies. The FERC issued Order No. 380 in 1984, which removed all gas costs from minimum bills, in an effort to motivate producers to renegotiate their high cost take-or-pay contracts with the pipelines and to eliminate the anticompetitive effect of minimum bills forcing customers, in particular LDCs, to buy from other than the least cost supplier. Despite being challenged by interstate pipelines as an unlawful abrogation of contracts by FERC, Order No. 380 has withstood judicial scrutiny.[20]

On October 9, 1985, shortly after the courts had declared SMPs and the blanket certificate programs illegal, the FERC issued Order No. 436 in a further attempt to:

- open up the transportation system;
- provide a framework for more "flexible" regulation in the future; and
- institute a transition mechanism for realigning contractual arrangements in the short run.

Order No. 436 contained three essential provisions:

(1) Any pipeline offering transportation services must offer the same to all potential users in a non-discriminatory fashion. The tariffs have to be cost-based (i.e., distance based), volumetric and differentiated by time of use. Further, intrastate pipelines must offer both firm and interruptible transportation service.

(2) Participating pipelines have to agree to allow their firm contract demand customers (principally LDCs and other interstate pipelines) the right to reduce their contract demand (or to convert it to firm transportation) by 15-25 percent per year over 5 years.

(3) Any pipeline that agrees to participate in the Order No. 436 program may be permitted to recover in its rate structure some portion of sums paid to producers to buy out take-or-pay liabilities. However, if and how these buyouts will be incorporated into the pipeline rates will be determined on a case-by-case basis.

It should be noted that Order No. 436 is a voluntary program and that pipelines which do not participate in the program may still provide transportation under NGA Section 7(c).[21]

Objections to various aspects of the Order have been forthcoming from all segments of the gas industry. Interstate pipelines, in particular, protested against the contract demand reduction clause and its implications for the incurrence of future take-or-pay liabilities. Challenges to the legality of the order eventually resulted in the D.C. Court of Appeals vacating the order on June 30, 1987. The court upheld most components of the program--in particular, the principle of nondiscriminatory transportation--but objected to several major aspects--most notably, the contract demand (CD) adjustment option and the failure of the FERC to adequately address the take-or-pay issue.

The FERC's reasoning with regard to CD adjustments was that they were necessary to ease LDCs out of long-term contracts with pipelines that were signed when pipeline system supply was the only available source of supply. These contracts were denying LDCs access to the spot market for cheaper gas supplies. Pipelines which had secured long-term supplies for these customers were thus left with the prospect of ever increasing take-or-pay liabilities if the CD option was exercised and purchases of system gas reduced. The court ruled that while the CD conversion option was consistent with the need for more flexible transportation, the FERC had not provided a compelling argument for CD reduction.

The main stumbling block to the court's acceptance of the Order, however, remained the acceptable resolution of the take-or-pay problem. The regulatory initiatives taken by the FERC in the 1980s had departed from the traditional regulatory objective of ensuring security of supply for pipeline customers, to one which emphasized equal access to lower priced gas for all consumers. To this end, the FERC, in Order No. 380 and its CD adjustment option, released customers for whom pipelines had contracted long-term supplies from their obligations to purchase this gas. This has had a severe impact on the interstate pipelines take-or-pay exposure. Under Order No. 436, although take-or-pay buyout costs could be recovered in a pipelines rate structure, it would be done on a case-by-case basis, opening the pipeline to challenges over such matters as whether or not the original contracts were "prudent."

The FERC has since issued an interim rule, Order No. 500 on September 15, 1987, the backbone of which is the FERC's response to the take-or-pay dilemma. The Commission has adopted a three-pronged approach to the take-or-pay problem, creating a new mechanism to direct-bill past take-or-pay charges, forcing producers to credit current transportation volumes against future take-or-pay liabilities, and providing pipelines with general guidelines to develop direct-billed surcharges for firm sales customers to alleviate future take-or-pay problems. In addition, the FERC eliminated contract demand reduction while choosing to keep contract demand conversions intact.

The most controversial provision of Order 500, the crediting mechanism, was strongly criticized by producers as providing too little preparation time for the affidavit requirements. Order No. 500-B, which was issued in October in response to this concern, deferred the take-or-pay crediting provision until January 1, 1988 and also postponed the right of LDCs to convert contract demand sales to transportation to the same date. Order No. 500-C, which was issued shortly after 500-B in December, changed the crediting rules with regard to casinghead gas, new gas, and gas released by intrastate pipelines and processing plants. A final ruling by the FERC on the issue of open access transportation should be forthcoming by mid-year.

The FERC has also had to deal with a vestige of the NGPA that had become known as the "old" gas cushion. This cushion, which had resulted from the decision to regulate, indefinitely, the price of old gas below market clearing levels, stimulated some inefficient purchasing practices on the part of interstate pipelines in the early 1980s. In particular, it allowed them the scope to pay above market clearing prices for "new" gas (also purchased under inflexible contracts), roll these prices in with low cost "old" gas, and still maintain an acceptable weighted average purchased gas cost. In the face of falling natural gas demand, interstate pipelines have since shut-in low cost gas while taking high cost gas to minimize the impact of take-or-pay liabilities. Another concern was that if prices of "old" gas were to remain below market clearing levels, a large amount of potential supply from this source would be lost because of inadequate incentives to produce it.

To address these inefficiencies, the FERC issued Order No. 451 in 1985. The essential element of the order is the establishment of an alternative ceiling price equal to the NGPA Section 109 price of $2.626 per MMBtu in April 1987. Because of the alternative nature of this new ceiling price, producers are not entitled to collect the new price without negotiating with pipelines. The negotiation procedure provides a balancing of rights between the producer and the purchaser. On one hand, the producer can force the purchaser to either pay more for the old gas or release the gas. On the other hand, the purchaser can terminate contracts--including the high-cost contracts covering some old gas. Both producers and pipelines have objected to certain provisions in the ruling. The Commission is expected to issue another rehearing order and the courts have yet to consider widespread challenges to the legality of the order.

Besides the finalizing and acceptance of an open access transportation program and complete deregulation of wellhead pricing, a consistent policy regarding the services and costs of services which an LDC should offer remains the most formidable obstacle to a competitive market in the U.S. Because each state is responsible for regulating the LDCs operating within its boundaries, regulation at the state level is likely to be tailored towards achieving certain objectives such as security of supply, low price or cross-subsidization of core customers that will vary depending on the mix of customers in the state. Indeed, the provision of transportation services by LDCs at reasonable cost is seen by many as crucial to the continued competitiveness of gas in the industrial and electric utility sectors, and to effective competition with the option of system bypass.[22]

To date, most states with significant industrial activity have instituted some sort of transportation mechanism for their LDCs. However, change in the traditional role of LDCs has been slow, not only because of the increased complexity of operating in the new contract market created by both gas-to-gas competition and competition with alternative fuels, but also because of the "institutional mentality" many LDCs acquired after years of operating in a regulated market.

2.3.2 The Canadian Experience

Progress in Canada towards a deregulated market, although initiated several years after the U.S., has proceeded at a much more rapid pace than evidenced in the U.S., largely due to the smaller scale of the Canadian industry. Canadian authorities continued to regulate both domestic prices--under the guidelines established by the Natural Gas Pricing Agreement of 1975 and subsequently under the NEP in 1980 and the Energy Pricing Agreements of 1981--and export prices--through the administration of a uniform border price based on the price of imported crude oil into Eastern Canada--until 1984. The first step toward loosening these price controls was taken in 1983 and was directed towards improving takes of gas from existing export contracts. The Volume Related Incentive Program (VRIP) was intended to stimulate export sales by allowing volumes in excess of annual established base volumes to be sold at a lower price.[23]

The continued poor performance of export sales prompted the formation of a market sensitive gas export policy in 1984. Under this policy, Canadian exporters were free to negotiate market responsive pricing and delivery terms with U.S. purchasers so long as the border price recovered all costs incurred in producing and transporting the gas to the border and did not fall below the Eastern wholesale price. This policy was subsequently revised, first in October 1985 when the producing provinces and the federal government agreed to an adjacent border test which required that the export price not be less than the domestic price paid in the adjacent region, and again on November 1, 1986 when the Federal Government agreed to replace the border price test with a price monitoring process, designed to ensure that export prices could not remain below domestic prices for a sustained period of time.

The Western Accord of March 1985 and the subsequent October 31, 1985 Agreement on Natural Gas Markets and Prices established both a framework and a timetable for the deregulation of natural gas pricing in Canada. Through these agreements, the governments of Canada, Alberta, Saskatchewan and British Columbia committed themselves to the establishment of a flexible and market-oriented pricing regime for domestic natural gas, in which there would no longer be a government role in prescribing prices. The timetable set for complete deregulation allowed for a 1-year transition period from Nov. 1, 1985 to Oct. 31, 1986, during which wholesale prices prescribed by the governments were frozen. However, industrial customers without gas sales contracts with LDCs were free to negotiate directly with producers during this period.

Since the signing of the October 31, 1985 Agreement on Natural Gas Markets and Prices, all segments of the industry have responded to, and incorporated within their functions, the essential characteristics of a market-oriented pricing regime. First on the agenda was the opening up of the two major trunk pipelines in Canada--Westcoast and TCPL--to those parties wishing to obtain transportation service. Essentially the problem was similar to that encountered in the U.S. but infinitely less complex as the special problems and liabilities of only 2 pipelines had to be resolved, whereas in the U.S. over 40 intrastate and interstate pipelines were differentially impacted by Order No. 436. Moreover, TCPL's take-or-pay situation had largely been resolved under the TOPGAS agreements so that no major disincentive existed for them to oppose open access except, of course, the danger that a substantial conversion of system sales to transportation might cause additional take-or-pay obligations to be incurred in the future and slow the recovery of prepaid take-or-pay volumes.

In implementing a direct sales mechanism in the TCPL transportation system a number of issues were addressed, most notably:

- the displacement provision in TCPL's tariff schedules stating that TCPL would offer certain types of transportation service if the "shipper gas . . . will not in whole or in part, displace a substitute for volumes of gas which any party has under contract to purchase from Trans-Canada";[24]
- whether inappropriate duplication of demand charges will result from possible displacement of one volume of gas by another; and
- how to equitably share the accrued take-or-pay liabilities of TCPL.

The decision of the National Energy Board was that the displacement provision included in TCPL's tariff schedules be removed in order that transportation service be made available to direct purchasers of natural gas, displacing supplies previously acquired by TCPL.[25] The Board also decided that the duplication of demand charges (also referred to as double demand charges) was inappropriate.[26] Double demand charges occurred when a customer who had previously purchased gas from a distributor arranged a direct purchase and, as a result, had to pay the demand toll twice, once to TCPL for service and once to the distributor to pay for the demand charges on the distributor's contract demand volumes which the direct sale had displaced.

The Board's solution to this problem was to implement the operating demand volume (ODV) concept for the purpose of determining demand tolls. Under this methodology, a distributor's ODV was to be determined as the contract demand, as specified in the CD contracts with TCPL, less the volume displaced by direct sales. Essentially the ODV mechanism is a device for decontracting on the part of distributors. The NEB had to deal with the issue this way because it lacked the legal authority to deal directly with TCPL distributor contracts by reducing the CD volumes.[27]

With regard to the equitable sharing of take-or-pay carrying costs, the Board recommended that it was fair and equitable to require non-system gas to bear some portion of the costs and that these carrying charges should be recovered in the Alberta cost of service.[28]

In a truly competitive gas market, competition should take place at the burner-tip as well as the city gate. In other words, end users wishing to contract directly with gas producers must be able to obtain transportation on the LDC serving that market as well as on the pipeline serving the LDC. Moreover, the cost of this service to the end-user should reflect the LDC's cost of providing it. To further facilitate burner-tip competition, if an end-user feels that the rates being charged by an LDCs are not competitive, he should have the option of "by-passing" that distributor by building an interconnecting pipeline between his facilities and the trunk pipeline.

The decision as to whether LDCs will provide transportation service and if so, at what cost, rests in the hands of provincial regulatory commissions and bodies. Traditionally these regulatory agencies have regulated burner-tip costs by determining an LDC's cost of service, allocating it to the various classes of customers and adding the resulting charge to the LDC's purchased gas costs. Jurisdiction over distributor by-pass has also traditionally been maintained by local regulatory agencies. However, in February 1987, the NEB ruled that it had jurisdiction in the area by deciding that Cyanamid Canada Inc. could build a pipeline connecting its facilities to TCPL, thereby "bypassing" its distributor, Consumers' Gas. The Ontario Energy Board protested this infringement on its jurisdiction and to date the Ontario Supreme Court and Federal Court of Appeals have ruled in its favour regarding this issue.

LDCs offer a wide array of services such as storage, load balancing, and transportation. A deregulated market environment requires that these services be unbundled so that the end-user can choose, and pay for, only those services which are required. Traditionally, regulators have attempted to keep residential gas costs low by subsidizing them with industrial tariffs that reflect the "value of service," which in a monopoly such as an LDC is usually quite high, rather than the actual cost to the LDC of providing that service. The provincial regulatory agency thus must approve the unbundled rates an LDC offers, while the LDC must obtain system supply reductions from its supplier.

The Ontario Energy Board in April, 1987 ordered the province's three major local distribution companies (Consumers' Gas, Union Gas and ICG Ontario) to separate their marketing and transportation functions, thereby allowing end-users the option to purchase gas directly from producers and use the distributors to transport the gas. Moreover, the Board ordered that the distributors' rates be unbundled as described above, with the intention that cross-subsidization (the subsidization of one rate class by another) would cease. Rate proposals by the three LDCs must now include separate rates for transportation, storage and load-balancing. No minimum volume requirements or contract terms can be included as part of the contracts between the LDCs and their customers. In addition, the postage stamp rate system, in which rates are based on geographic location and gas volumes taken, will be maintained, although the Board may set rates to compete with bypass options.[29]

Other provinces have instituted some form of separate transportation service requirement on their LDCs. Manitoba has recently replaced its transportation service with a buy-sell mechanism in which an LDC reduces its contracted volume with TCPL by the amount of firm service bought on behalf of the end-user purchaser, purchases the gas from the end-user at the LDC's average cost of gas, and resells the gas to the end-user at his facilities at the retail rate applying to that class of service. Alberta LDCs, although they do not offer interruptible transportation service, do offer firm transportation service to direct purchasers. LDCs in Quebec offer both interruptible and firm transportation services; however, in December 1987 Quebec's Regie de l'Electricite et du Gaz ruled that distributor's rates would not be unbundled.

To reflect the current gas surplus in Canada and the opportunity it presents to Canadian consumers in the form of lower prices, and to introduce some flexibility into existing contracts, long-term contracts between TCPL and its principal customers (mainly LDCs) have had to be renegotiated. Western Gas Marketing Ltd. (WGML), a wholly owned subsidiary of TCPL Ltd. whose primary function is the managing and marketing of TCPL's gas supplies, was responsible for this complex process. They approached the task of renegotiation by introducing a net-back pricing stucture wherein TCPL's producers would receive the net revenue remaining after deducting all transportation, administration and take-or-pay charges from domestic and export revenue. The pricing clauses in TCPL-producer contracts (which had been overridden by regulations) were replaced by this netback structure for a period of 2 years during which time take-or-pay provisions were also suspended. No volume or term renegotiation took place in either producer-TCPL or TCPL-distributor contracts.

The renegotiated contracts generally utilize producer sponsored discounts to stream competitively priced gas to the different sectors being served by the LDCs. Each distributor's rate schedules, arising from the gas pricing agreements, were reviewed by their respective provincial regulatory bodies in Quebec, Ontario, and Manitoba. Approval was obtained from Quebec's Regie de l'Electricite et du Gaz, who agreed that the actual cost of gas had been properly determined through negotiation between buyer and seller and that the price discounts listed by the distributor were being supplied by the Alberta producer.

The Ontario Energy Board, however, expressed concern that these discounts could interfere with its mandate to set prices in Ontario and could possibly lead to undue price discrimination between different classes of consumers. The Board did, however, approve new pricing schedules for the 1986-1987 contract year, with approval for the second year (October 31, 1988) conditional upon Western Gas Marketing Limited and the distributors addressing certain jurisdictional concerns identified by the Board. The Board recently accepted new contracts for the 1987/1988 contract year. While these contracts still utilized streamed discounts and contained high prices for core customers, the Board found that prevailing circumstances outside of Alberta--the monopoly position of WGML/TCPL with support from the NEB's self-displacement provision and the removal permit policy of the Alberta government--prevented provincial LDCs from meeting its market deregulation criteria.

The Manitoba Public Utilities Board (PUB) review of the distributor's rate schedules covered essentially the same issues addressed in Ontario. A key difference, however, was the position taken by the Manitoba government that the long-term contracts between Western Gas

Marketing Ltd. and the distributors should be abrogated and replaced by contracts with one or more suppliers at lower prices. The basis for this action was a report by the Manitoba PUB which concluded that a free competitive market for natural gas sales to distributors for resale to "core" customers did not exist, and that if there was such a free market, the average purchase price faced by LDCs in the province would be \$2.00 per Mcf compared with the prevailing price of \$2.65 per Mcf.[30] The Manitoba PUB approved the distributors rate schedules to October 31, 1987 but directed the distributors to prepare themselves for tendering of their gas supplies.

The Manitoba Oil and Gas Corporation, a Crown corporation, announced the signing of a 15-year, direct-sales contract with 3 Alberta marketers at a sale price below \$2.00 per Mcf in July 1987. The government also announced its intention to buy the provincial gas distribution system of the Inter-City Gas distribution company, to be operated by the Manitoba Oil and Gas Corporation. In response to this attempt to obtain cheaper gas for core market customers and abrogate TCPL-distributor contracts, and in anticipation of similar action by Quebec and Ontario, the government of Alberta tabled legislation which would allow the province to set the terms of new and old removal permits and thus prevent the displacement of gas supplies under TCPL-distributor contracts by new distributor contracts. The NEB has since refused Manitoba's request for transportation on TCPL (in October 1987) on the basis that the direct sale agreement was essentially an artiface for self displacement.[31] Contracts between Western Gas Marketing Ltd. and Manitoba's provincial distributors were subsequently renegotiated at significantly lower prices and the Manitoba government has since renounced its intention to buy the provincial distribution system.

The conflict described above has focused attention on what is perhaps the most controversial aspect of Canadian deregulation--the right of the core market to participate in the marketplace and obtain its own gas supply (either directly by entering the direct sales market or indirectly by having the LDC enter the direct sales market on its behalf), rather than relying on TCPL's system supply. The essential elements of the debate are that the producing provinces, particularly Alberta, feel that:

- sanctity of existing contracts is essential for an orderly transition to a deregulated market as envisioned under the October 31 agreement; and

> - because the core market requires long-term supply protection, it should pay higher prices, something which is critical to the financial well being of producers and to provincial royalty revenues.

The consuming provinces, mainly Ontario and Manitoba, contend that core customers should have their gas supplied at prices similar to those offered large industrial users, or at least have the right to negotiate directly with producers for their own supply.

Throughout this conflict, however, a widely accepted definition of what actually constitutes the core market and what (if any) type or term of supply assurance is required by these customers was not formulated. The Pipeline Review Panel (PRP) did tentatively define the core market as,

> those customers which require both a secure supply of gas and a transportation service from (a) distributor and are dependent on it for such a supply and service.[32]

The Alberta PUB and ERCB have based a definition of the Alberta core market on this approach in a recent inquiry. They define the Alberta core market as customers in the residential and commercial markets along with certain small volume industrial users.[33] In the same inquiry, the two organizations followed a PRP recommendation by proposing that core market requirements be protected by long-term contracts (for terms of 10 to 15 years). However, these consumers could obtain this protection either,

> through reliance on gas utility companies (who would be required to establish an appropriate portfolio of long-term supplies), or through direct sales arrangements with producers or brokers, provided these direct sales involve long-term commitments on both sides.[34]

Another important element underlying this debate was the presence of the export surplus rule which, at the national level, required that 15 years of current production remain in the ground to assure domestic consumers of a secure supply before exports would be permitted. Gas producers and the Alberta Government contended that the maintenance of this surplus was inconsistent with price deregulation as it removed the onus from consumers, especially in the core market, to worry about security of supply. Consumers could thus conceivably contract for low cost gas on a short-term basis knowing that their supply was protected in the long term.

This element of distortion was removed from the marketplace as of September 9, 1987 with the announcement by the NEB of its intention to move to a "Market-Based Procedure" for determining the surplus of natural gas in Canada available for export. Under the new procedure there is no formula for determining an exportable surplus. Instead, the Board will monitor the gas supply/demand situation on an ongoing basis and conduct public hearings for each export proposal (see Chapter 5).[35]

While the removal of a formal surplus test is unlikely to have any impact on exports in the short term due to the large gas surplus that was built up over the past decade, it may have significant psychological impact on the domestic gas market. The ruling is looked on with favour by gas producers and the Alberta Government because it places the responsibility of obtaining secure supplies on the shoulders of consumers. While it is highly unlikely that LDCs will be permitted to displace existing contracts with new ones, the ruling might reduce the difficulties that groups of core customers, such as municipalities or hospitals, are experiencing in obtaining the requisite removal permits to allow direct sales arrangements to be consummated. There are, however, numerous complexities and issues to be resolved by all parties if these type of sales arrangements are to proceed in an efficient manner.[36]

2.4 Features of Today's Natural Gas Market

Deregulation, excess gas supplies, and low oil prices have combined to radically alter traditional marketing arrangements in the gas industry and have also had a severe impact on gas prices. The current evolution towards a deregulated market, although by no means complete, has encouraged increased competition in the industry by allowing prices to be market determined and by increasing the number of buyers and sellers in the market through improved access to pipeline facilities for transportation service. Innovative marketing techniques have been developed to provide the numerous cash starved producers holding shut-in reserves and/or excess deliverability with access to end-use markets. Low oil prices have further intensified competition in the fuel switchable industrial and electric utility sectors. Gas sold to these sectors must be provided under flexible pricing arrangements if gas is to maintain its competive position with residual fuel oil.

The contrast between traditional gas marketing and today's gas marketing is illustrated in Figure 2.1. The complexity and competitiveness of the new market is evident in the increased flexibility and number of options that the different segments in the industry now have. Producers no longer have to dedicate their reserves to pipeline companies as they did in the traditional marketing arrangement. Today this option still exists but they may also sell gas directly to individual end-users and/or LDCs or indirectly through gas marketing or brokerage companies.

Conversely, end-users in the various sectors no longer have to obtain all of their supplies from the LDC serving their area. Electric utility and industrial gas consumers can now purchase their gas from four possible sources:

- directly from gas producers;
- indirectly through gas marketers or brokers;
- from gas pipeline companies; or
- from LDCs in the traditional manner.

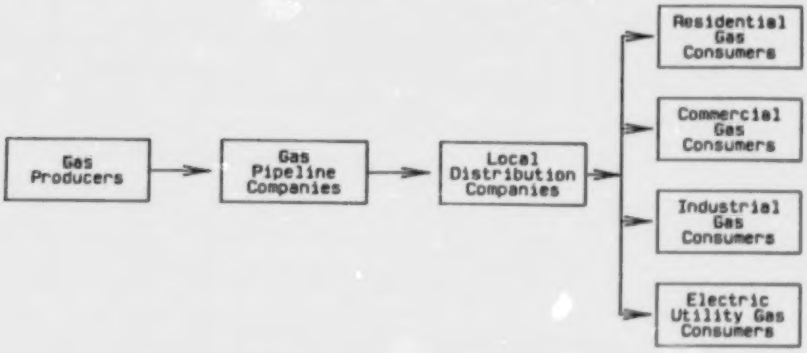
LDCs are also freed (to some extent) from the traditional arrangement of obtaining all their system supplies from pipeline companies. They now have the option of diversifying their supply portfolio to minimize gas purchase costs by obtaining some portion of their supplies from gas producers, either directly or indirectly through gas brokers. In Canada, the latter option is still quite limited because long-term contracts between LDCs and TCPL (which supply most of the LDCs' requirements) do not expire until the mid-1990s.[37]

Commercial and residential customers also have two options--to purchase gas from an LDC or from gas brokers. However, unless the individual end-user requirements are quite large (as is the case for some commercial customers), the cost of arranging a contract with a gas broker and obtaining the necessary transportation certificates must be prohibitively expensive and time consuming. In some instances a group of consumers, such as a municipality or group of hospitals, must be structured to achieve a purchase volume sufficient to make such an arrangement more attractive than simply purchasing the gas from an LDC. However, this concept has encountered considerable resistance in both the U.S. and Canada.[38]

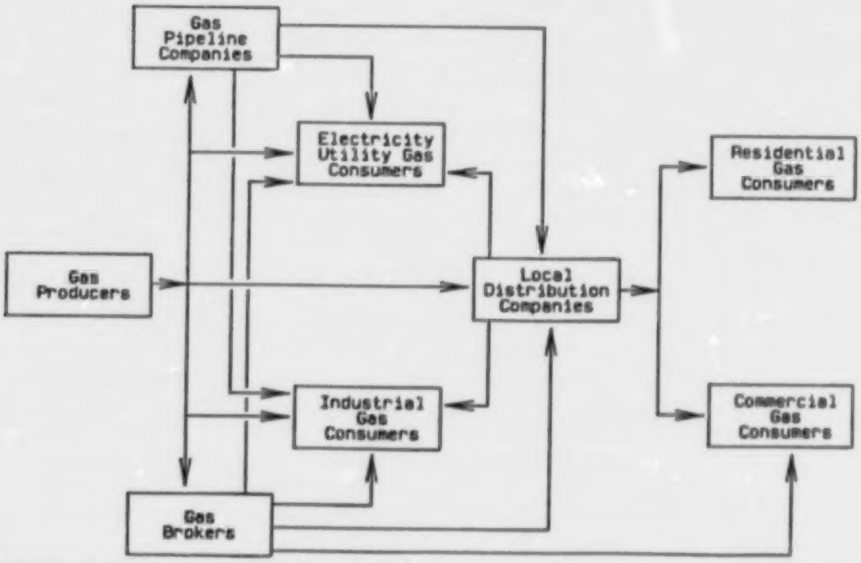
The change in emphasis in the role of the pipeline companies in today's gas industry is also evident in Figure 2.1. Whereas

Figure 2.1
Trends in Natural Gas Marketing

Traditional Gas Marketing


Gas Producers
Gas Pipeline Companies
Local Distribution Companies
Residential Gas Consumers
Commercial Gas Consumers
Industrial Gas Consumers
Electric Utility Gas Consumers

Today's Gas Marketing


Gas Pipeline Companies
Electricity Utility Gas Consumers
Residential Gas Consumers
Gas Producers
Local Distribution Companies
Industrial Gas Consumers
Commercial Gas Consumers
Gas Brokers

SOURCE: Canadian Energy Research Institute.

traditionally they have served the merchant function of obtaining gas supplies for the various LDCs in their service area, an increasing emphasis is being placed on their function as a transporter of natural gas. Their merchant function has been displaced by the emergence of gas marketers and brokers, direct sales agreements and the growing importance of the spot market in the U.S.

The increasing importance of the transportation function is evident in the increased volumes of gas now being transported under common carriage terms in Canada and the U.S. It is estimated that on TCPL, between 10 and 15 percent of system sales have been displaced by direct sales within the last 2 years.[39] In the U.S., volumes transported to end-users have increased from 1397 Bcf in 1982 (about 9 percent of all gas delivered to consumers) to over 3400 Bcf in 1986 (about 24 percent of total gas delivered) and could be as high as 40 percent of total deliveries in 1987.[40]

A significant share of the increase in common carriage transportation volumes has been due to the growth in size and importance of the gas marketing and brokerage sector of the industry. This growth is primarily a function of the services these companies provide in the current market environment of excess gas supply and deregulation. Some of the more important services include:

- the bringing together of sellers (gas producers) and end-users who otherwise might not be aware of each other's requirements because of the size of the market;
- reducing the complexity of the contract process by arranging transportation services and price terms;
- serving as supply aggregators by bringing together a diverse group of producers and offering their production as a package; and
- providing producers who might otherwise not have the expertise or manpower to participate in the direct sales market, and who have excess deliverability or shut-in reserves, with access to incremental markets.

Essentially, the gas marketing and brokerage sector has, through the above services, increased the number of market participants and degree of competition on both the supply and demand side of the market.

The ready availability of transportation on TCPL and increasing availability on U.S. pipelines has, as discussed above, resulted in an increased volume of direct sales between gas producers and brokers, and end-users. In Canada, several types of direct sales arrangements have evolved as well as a mechanism to allow Western Gas Marketing Ltd. to compete with these purchases. There are essentially four alternatives for consumers interested in obtaining discount gas:

- Umbrella T-Service, which has LDCs reduce their sales contracts with TCPL by the volume displaced by end-user direct purchase arrangements and, concurrently, enter into transportation contracts with TCPL with volumes equal to the displaced volumes. End-users arrange price terms with the seller, either a gas producer or broker, and must also obtain transportation service on the LDC;

- Contract carriage, which has the direct sales participants arrange price terms and all transportation required from wellhead to burner-tip;

- Buy/Sell at Alberta border, which has the end-user buying gas from a producer or broker at the Alberta border and simultaneously selling the gas to the LDC at the same point. The LDC then arranges for transportation on TCPL from the Alberta border to its service area and sells the gas to the user under the appropriate rate class. Although the user pays the same price at the burner-tip as previously, savings result from the spread between the price paid at the border and the price at which it was sold to the LDC; and

- Competitive Marketing Program (CMP), which allows Western Gas Marketing Ltd. to compete with direct sales and essentially consists of a discount destined directly to a particular end-user through the normal sales arrangement.

There are, however, numerous obstacles facing an end-user selecting the direct sales route. These include obtaining Alberta gas removal permits which may be delayed or denied depending on the pricing terms; the incurrence of financial risks and burdens; the requirement that the end-user accurately forecast natural gas requirements and be subject to balancing penalties for over or under consumption; and the transaction and administrative costs involved in carrying out the direct sales arrangement. Of the four alternatives, CMPs involve the lowest degree of risk and transaction complexity primarily because Alberta removal permits are not examined as closely as in the other alternatives and because there is not a need to arrange for transportation service. Customers and distributors also have long-term supply backup under this arrangement.

In the U.S., direct sales usually proceed via contract carriage. A contract is signed between a producer or broker and an end-user and it is the responsibility of the consumer to arrange transportation to his facilities. A vigorous marketplace, known as the spot market, has developed in the U.S. and has become the dominant forum for arranging direct sales agreements. The supplies on the market are made available by producers whose reserves would otherwise be shut-in, or who have excess deliverability either because past drilling programs overestimated demand, or because the gas was released from previous long-term contracts with pipeline companies. Consumers participating in the market come from all end-use sectors although they are generally LDCs, large industrials or electric utilities.

Generally the spot market functions as follows. An end-user will announce that he intends to purchase a certain amount of gas over a certain time frame on the spot market. Producers and gas brokers participating in the spot market then submit spot bid prices at which they would be willing to provide some portion of, or the total volume being requested. The user examines the bids and selects those that meet his requirements at minimum cost. The onus is then upon the end user to arrange or have arranged, the requisite transportation from the supply source of the gas to his facilities. Obtaining this transportation is the major obstacle facing spot market participants, given the uncertainty regarding Order No. 500 and its implications for both producer and pipeline actions.

Prices observed in the spot market are being increasingly relied upon as an indicator of the current and future demand/supply situation because of the large share of total gas requirements, about 24 percent in 1986, being obtained within it. Further, because of the large number of buyers and sellers participating in the market and the vigorous competition being evidenced, it is the closest indicator of a "competitive" price level that is available to industry participants.

However, the prolonged surplus in gas supplies have likely exaggerated the role of the spot market in the U.S., and the direct sales market in Canada, in terms of the volumes being purchased and the prices being paid. Surplus gas has removed the incentive for buyers to enter into long-term contracts and pay the premium price necessary to obtain secure supplies, although they would certainly sign a long-term contract at current spot prices if a willing producer could be found. This situation has been exacerbated because deregulation occurred concurrently with the gas surplus. The resulting new markets and improved transportation access have provided cash flow driven producers with a market mechanism to sell their gas which, because of the gas surplus, they have done so at prices below the cost of replacement.

In Canada, domestic gas prices measured at the Alberta border have fallen from $2.90 per Mcf in November 1986 to $2.02 (Cdn.) per Mcf in April 1987. Over the same period, long-term firm contract prices have fallen from $2.95 to $2.19 per Mcf while short-term firm prices have fallen from $2.37 to $1.57 per Mcf, indicating the price reductions which large industrial users in Eastern Canada have been receiving.[41] A similar decline in prices has been observed in the U.S. The average wellhead price of gas has fallen from $2.88 (U.S.) per Mcf in January 1985 to $2.06 per Mcf in June 1987. Spot market prices have fallen from $2.60-$2.90 per Mcf in the Texas Gulfcoast Market to $1.30-$1.42 per Mcf over the same period.[42]

However, cold weather in the U.S. during November and December has given market participants an indication of how the U.S. spot market wil function in the future. Spot prices increased $0.80 (U.S.) per MMBtu in some markets over a 1-month period as gas supplies tightened significantly. Because spot prices began to exceed both pipeline commodity gas prices and residual fuel oil prices, a significant return to system gas and fuel switching was observed. While some analysts attributed the rise in prices to the crediting mechanism of Order 500, most thought that market fundamentals were asserting themselves.[43] That is, gas supplies tighten during peak demand periods, prices rise and if they exceed residual fuel prices, some portion of the market switches. During the summer when demand is not as strong, spot prices are likely to fall in order to recapture switchable customers.

Although gas-to-gas competition has resulted in gas prices generally below the Btu equivalence price of oil in the spot and direct sales market, the presence of a significant switchable market in the U.S. (exceeding 3 Tcf) in combination with volatile oil prices, has resulted in the price of residual fuel oil in the industrial and electric utility sectors forming a ceiling on the general level of gas prices in North America. If natural gas prices begin to exceed fuel oil prices, some portion of the market will switch to oil. The resulting loss in gas demand will put downward pressure on gas prices to recover this lost market share.[44] The fall in crude oil prices in early 1986 from $28.00 (U.S.) per barrel to as low as $10.00 (U.S.) per barrel provided some evidence of this mechanism. Natural gas lost a significant share of the market as industrial and electric utility users in the U.S. having dual-fired capability switched to lower cost fuel oils.[45]

The resulting loss in gas demand has prolonged the gas surplus and although oil prices have recovered considerably in the past year to about $18.00-$20.00 (U.S.) per barrel, natural gas prices have not risen proportionately due to intense gas-to-gas competition. However, natural gas will face significant interfuel competition from fuel oil in the near term as oil prices are anticipated to remain soft. As the gas surplus diminishes, gas-to-gas competition will lessen and prices in the spot and direct sales markets will begin to increase. As gas prices begin to impinge on fuel oil prices, it is essential that natural gas markets exhibit the flexibility necessary to meet this competition.

To some extent, this flexibility is provided by market deregulation, the emergence of the spot and direct sales markets due to improved transportation access, and shorter-term contracts. Longer-term contracts, such as those that might be required to justify construction of new gas fired electric generation facilities and new pipeline projects, must include flexible pricing provisions (such as indexing the price of gas to competing fuels) if they are to maintain the competitiveness of gas with other fuels.

However, whereas gas prices could be explicitly tied to oil prices in a regulated market (as was done in Canada), in the new and still evolving deregulated market this is no longer the case. The ceiling imposed by the price of oil is in a sense "voluntary". Gas producers in the current surplus environment will continue to meet fuel oil competition to the extent permitted by the underlying cost structure of remaining gas supplies. As the surplus diminishes, gas prices will have to rise to cover replacement costs. If the resulting price is higher than the price of oil, some load loss in the industrial and electric utility sectors is inevitable. The resulting gas price will then reflect the North American gas demand/supply balance rather than the world oil price.

2.5 Summary

Natural gas markets have changed dramatically over the last decade. Deregulation and improved transportation have increased competition in all sectors of the industry. Despite soft oil prices, excess gas supplies in combination with the above have resulted in gas prices being determined primarily by gas-to-gas competition in the spot and direct sales markets. As the gas surplus diminishes and gas supplies tighten, continued improvement in transportation availability on both pipelines and LDCs and flexible contracting practices will be required for gas to meet the competitive pressure of alternative fuels.

It must be remembered that the majority of issues with which the natural gas industry is currently grappling are short term in nature and stem primarily from the presence of excess gas supplies. The availability of low cost gas supplies has been the principal cause of the take-or-pay problem in the U.S., as end-users leave a pipelines system sales to purchase cheaper supplies in the spot market. This has disrupted progress in the movement towards an open access transportation network in the U.S. as pipelines balk at becoming open access transporters because of the impact such a system might have on future take-or-pay liabilities.

Similarly, the low gas prices resulting from gas-to-gas competition have prompted many industrial users in Canada to leave LDC sales and participate in the direct sales market. The potential loss in royalty revenue to the producing provinces, primarily Alberta, has been reflected in their reluctance to issue the necessary removal permits for low price transactions. This is especially true for sales to the non-switchable core market because of their need for secure supplies and the price premium which producing provinces feel should be attached to such supplies. The Alberta government has recently changed the provincial gas royalty regime in an effort to recoup what it perceives to be a fair value for its share of the resource. The new regime essentially establishes a minimum floor price for the purpose of calculating royalties. Producers who sell gas at prices below 80 percent of the average market price must pay royalties based at 80 percent of the market price.

While the sanctity of existing TCPL-distributor contracts is consistent with the desire for an orderly transition to a deregulated environment, denying core market access to the direct sales market is somewhat inconsistent with the essential precepts of deregulation. Only a small portion of the "core" market (e.g., hospitals, municipalities, school boards, etc.) is actually capable of contracting directly with producers or brokers. With the removal of the gas surplus, the onus is upon these consumers to obtain secure supplies through appropriate contracting practices. Moreover, any contracts that are signed will either be short term or, if long term, will contain pricing provisions that either require prices to be renegotiated periodically or that tie gas prices to a mutually acceptable index. Consumers will then deal with the necessity of either paying the prevailing price for gas which, if the market has tightened, could be considerably higher than the price that they could obtain from an LDC, or of paying some penalty to return to distributor sales.

An important facet of this study is its examination of longer-term market forces and trends that have been somewhat obscured by shorter-term phenomena such as the gas bubble and concurrent low gas prices. As supply and demand come into balance the market will reorient itself from a buyers market to a sellers market. As the market begins to favour sellers, current barriers to exports such as Order No. 256 and slow implementation of open access transportation in the U.S. as well as other regulatory problems and delays should lessen dramatically. Spot gas and direct sales contracts will likely shrink in favour of longer-term contracts with price renegotiation provisions as security of supply becomes an increasingly important consideration.

In this new environment, gas-to-gas competition will lessen as supply tightens and gas will begin competing against alternative fuels rather than against itself. Besides the future prices of alternative fuels, a major determinant of future gas prices and demand will be the cost of finding and developing new reserves. This study will hopefully provide a synthesis of these long-term determinants of natural gas supply and demand and an indication of their implications for prices and volumes in the context of a deregulated continental gas market.

Footnotes

[1] An example of how this type of result could have occurred is given in P. R. Carpenter, H. P. Jacoby and A. W. Wright, "Adapting to Change in Natural Gas Markets," in Energy Markets and Regulation, edited by R. L. Gordon, H. D. Jacoby and M. B. Zimmerman (Cambridge, Massachusetts: The MIT Press, 1987), pp. 14-15.

[2] Many different estimates exist regarding the size of take-or-pay liabilities of U.S. pipelines. This estimate was reported in Natural Gas Week, volume 3, no. 36, September 7, 1987, p. 1 and is taken from a study released by the Interstate Natural Gas Association of America.

[3] The American Gas Association (AGA), Gas Facts 1985, p. 62.

[4] Canadian Gas Association (CGA), 1965-1985, Historical Statistics of the Canadian Gas Industry, pp. 12 and 46.

[5] United States, Department of Energy, Energy Information Administration, Natural Gas Annual 1985, DOE/EIA-013, (Washington, D.C.: Energy Information Administration, 1985), p. 59.

[6] For a detailed history on the development of Canadian regulation of natural gas exports, see G. C. Watkins, The Development of Canadian Controls on Natural Gas Exports (Boulder, Colorado: ICEED, 1987).

[7] For a detailed chronology of these events see A. Plourde, Oil and Gas in Canada: A Chronology of Important Developments 1941-1986, Energy Study No. 86-5, Institute for Policy Analysis (Toronto: University of Toronto, November 1986).

[8] A. Plourde (1986) op. cit. also provides a concise summary of the essential features of the NEP and its implications for natural gas pricing.

[9] P. R. Carpenter, H. P. Jacoby and A. W. Wright, "Adapting to Change in Natural Gas Markets," op. cit., p. 11.

[10] In a report entitled Canadian Natural Gas: Supply and Requirements (1975), the NEB concluded that domestic non-frontier natural gas supplies would be insufficient to meet Canada's short- to mid-term domestic and export requirements.

[11] TCPL essentially nominates prepaid gas for delivery during winter months, withholds from the price otherwise payable to producers the amount which was advanced to producers for this gas, and pays this amount to the TOPGAS consortium. Producers receive any surplus if the price is higher than the initial price they received under the TOPGAS advances; however, if the price is less, they are liable for the difference.

[12] TOPGAS carrying costs are paid by all producers moving gas on TCPL and average about $0.26 per Mcf for TCPL producers and $0.11 per Mcf for non-system producers.

[13] United States, Department of Energy, Energy Information Administration, Natural Gas Annual 1985, DOE/EIA-013, (Washington, D.C.: Energy Information Administration, 1985), pp. 213-214. Industrial and Electric Utilities demand for natural gas fell by 1.26 Tcf and 0.58 Tcf respectively, for a total of 1.84 Tcf between 1979 and 1983.

[14] Canadian Gas Association (CGA), 1965-1985 Historical Statistics of the Canadian Gas Industry, pp. 12 and 46.

[15] See Footnote 1.

[16] United States, Department of Energy, Energy Information Administration, Natural Gas Annual 1985, DOE/EIA (Washington, D.C.: Energy Information Administration, 1985), p. 61.

[17] Surplus Canadian productive capacity is estimated by the National Energy Board, Canadian Energy Supply and Demand 1985-2005 (Ottawa, Canada: National Energy Board, 1986), Table A5-3, p.259. U.S. estimate of surplus productive capacity is reported in Natural Gas Market Report, vol. 3, no. 16, September 3, 1987 and is estimated by the American Gas Association.

[18] The essential elements of the Special Market Programs and their demise is described in United States, Department of Energy, Energy Information Administration, A Chronology of Major Oil and Gas Regulations Issued Through October 1985 (Washington D. C.: Energy Information Administration, 1986), pp. 32-43.

[19] Ibid., pp. 32-43.

[20] Ibid., pp. 32-43.

[21] United States, Department of Energy, Energy Information Administration, Natural Gas Monthly March 1986, Feature Article "An Analysis of FERC Order 436", (Washington D. C. Energy Information Administration, 1986).

[22] An example, which was reported in Natural Gas Intelligence, vol. 6, no. 50, September 7, 1987, concerns the Virginia PUC's decision to decrease the interruptible transportation rate on a state LDC from $0.40 per Mcf to $0.18 per Mcf. The basis for the decision was a study of the returns the utility was collecting from different customer classes. Residential users were found to be bringing in a minus 5 percent return on sales while general system customers were bringing in plus 6 or 7 percent. In contrast, sales to industrials were bringing in a 50 percent to the utility and transportation revenues were returning 34 percent.

Another example, cited in the same issue of Natural Gas Intelligence, concerns an Illinois utility charging $0.70 per Mcf to transport gas a distance of three miles.

[23] At the time the base export price was $4.40 (U.S.) per Mcf. Volumes in excess of 50 percent of NEB licenses could be sold for $3.40 (U.S.) per Mcf.

[24] National Energy Board, Reasons for Decision In the Matter of TransCanada Pipelines Limited Availability of Service (Ottawa: Minister of Supply and Services, May 1986), p. 4.

[25] Ibid., p. 6.

[26] Ibid., pp. 6-8.

[27] Ibid., p. 9.

[28] See Footnote 12.

[29] The OEB recently granted Cyanamid Canada an interim transportation rate on Consumers' Gas distribution network of $0.15 per gigajoule. Although this is lower than the previous T-rate of $0.20 per gigajoule, it is about 3 times the cost Cynamid believes it would incur to construct their own pipeline and bypass Consumers' Gas.

[30] Natural Gas Market Report, vol. 3, no. 8, May 8, 1987, pp. 2-4.

[31] Self displacement essentially consists of an LDC displacing CD contracts with direct purchase gas and as a result effectively abrogates those CD contracts. The NEB in its May 1986 Reasons for Decisions in the Matter of TCPL Availability of Services, found that self displacement was not within the intent of the October, 1985 Agreement on Natural Gas Markets and Prices.

[32] Canada, Pipeline Review Panel. A Review of the Role and Operations of Interprovincial and International Pipelines in Canada Engaged in the Buying, Selling, and Transmission of Natural Gas (Ottawa: Supply and Services, June 1986), p. 10.

[33] Alberta, Energy Resources Conservation Board and Public Utilities Board. Gas Supply and Transportation Service Inquiry (ERCB and PUB, Alberta: December 1987), p. 20.

[34] Ibid., p. 11.

[35] The Board's views are expressed in detail in National Energy Board, Reasons for Decision in the Matter of Natural Gas Surplus Determination Procedures (Ottawa: MInister of Supply and Services, July 1987).

[36] The ERCB and Alberta PUB (op. cit.) provide a good discussion of some of these issues.

[37] Canadian LDCs, as noted in Footnote 31, are expected to honour existing CD contracts with TCPL that do not expire until the early 1990s. They will thus not be able to effectively enter into the direct sales market until these contracts expire. In the U.S., a study by the American Gas Association (reported in the AGA, Gas Energy Review, vol. 15, no. 9, September 1987) showed that LDCs purchase over 20 percent of their supply under short-term contracts in the spot market.

[38] In Canada two municipal groups in Ontario, Metropolitan Toronto and Ottawa-Carlton, have expressed interest in obtaining their gas supplies in the direct sales market. They have encountered substantial difficulties in obtaining the necessary removal permits from the Government of Alberta which opposes this type of arrangement. Also, the Alberta Government has rejected an attempt by 12 Calgary hospitals to obtain direct sales gas. A group of hospitals in Washington D.C. encountered stiff opposition from the LDC serving that region in their attempt to purchase gas on the spot market. The gas finally started flowing 2 years after the initial contract was signed.

[39] Canada, Standing Senate Committee on Energy and Natural Resources, no. 10, June 8, 1987 (Ottawa: Supply and Services 1987), p. 58 and p. 62.

[40] American Gas Association, Gas Energy Review, vol. 15, no. 9, September 1987, p. 6.

[41] Canada, Energy, Mines and Resources, Price Monitoring Report (August 27, 1987).

[42] Average wellhead prices from United States, Department of Energy, Energy Information Administration, Natural Gas Monthly May 1987 (Washington D.C.: Energy Information Administration, 1987), p. 42. Spot price taken from Natural Gas Intelligence, vol. 4, no. 17, January 14, 1985 and vol. 6, no. 39, June 15, 1987.

[43] The take-or-pay crediting mechanism of Order No. 500 was cited as a possible cause of spot market price increases because of the possibility that producers were diverting production away from the spot market to avoid having to provide take-or-pay credits. In addition, by holding gas off the market they could conceivably leave pipelines with no choice but to increase takes of higher price system gas.

[44] Some economists have speculated that if gas prices were greater than oil prices for a sustained or indefinite period of time, it could result in a pipeline's death spiral. Decreased throughput on the pipeline would result in higher unit transportation costs which would increase prices and result in further load loss.

[45] The AGA estimated that switching away from gas to competitive fuels resulted in 618 Bcf of load loss in 1986 of which 490 Bcf was to crude oil products. The AGA also estimated that about 200 Bcf of the loss to crude oil would be recovered by gas if crude oil prices were $20.00 (U.S.) per barrel. American Gas Association, Gas Energy Review, vol. 15, no. 9, September 1987., pp. 2-5.

Chapter 3

THE SUPPLY OF NATURAL GAS IN CANADA AND THE U.S.

3.1 Introduction

As discussed in Chapter 2, prices and business practices in today's natural gas industry are largely determined by the presence of excess gas supplies. In the increasingly competitive market environment evolving in Canada and the U.S., this situation cannot persist. Low prices will result in a tightening of gas supplies and eventually gas demand and supply will come into a rough balance. The resulting level of prices must in the long term reflect the full-cycle costs of adding new reserves to maintain sufficient supplies to meet the quantity of gas demanded at that price. The magnitude and underlying cost structure of the undiscovered resource base will also become an increasingly important determinant of long-term prices and consumption levels. Higher prices will signal both the economic opportunity to explore for and develop higher cost gas supplies, and the approaching exhaustion and need for a transition to alternative energy sources to meet national energy requirements.

This chapter is intended to serve two purposes. First, we wish to provide readers who are not overly familiar with the natural gas industry with some background into the two major components of natural gas supply--the pipeline transportation network and the exploration, development, and production process. Salient statistics on reserves, production, and other key indicators of natural gas supply are also presented and discussed. Second, because the GRI North American Regional Natural Gas Model requires a careful specification of the full spectrum of possible future gas supplies, we examine the ultimate potential and costs of conventional gas supplies as well as frontier and nonconventional gas supplies. This requires a discussion of historical supply costs and indicators of future cost trends such as field sizes and finding rates.

The first section of the chapter provides a description of the existing pipeline network and current transportation costs as well as a discussion of the exploration and development process, outlining some key variables affecting costs. The next section examines the established conventional resource base in Canada and the U.S. Important historical trends in reserves are identified and a simple supply cost analysis is provided to serve both as a basis for comparing costs in Canada and the U.S. and to provide some evidence for the resource cost curves that are used in the modelling framework. Next, the potential for frontier and nonconventional gas supplies is discussed, also in terms of cost and volumes. The final section provides an outlook for future natural gas supplies in both the short and long term.

3.2 The Components of Natural Gas Supply

It is perhaps a misnomer to speak of natural gas supply when one is really referring to two distinct processes--the exploration, development and production process, and the distribution of natural gas from the wellhead to end user--whose complex interaction results in a supply of natural gas being available at a certain price. Any examination of the history and future of natural gas supply in Canada and the U.S. must be addressed in the framework that these components establish for industry participants.

3.2.1 The Natural Gas Distribution System

Early in the history of the petroleum industry, the most important distinction between crude oil and natural gas was the marketability of each product. Since the facilities to market gas were not yet in place, gas was viewed as an unwanted by-product of oil exploration and was either flared, shut-in, or, if possible, consumed in the immediate vicinity. Over the last 30 years, the requisite infrastructure of gathering, storage, and transportation facilities has been constructed in both Canada and the U.S. so that consumers in nearly all regions have access to competitively priced gas. Natural gas is now viewed as a valuable commodity and is as sought after as crude oil.

The first stage in the distribution process is the gathering and processing of gas from the various well sites. Natural gas liquids (NGLs) are generally removed from the gas before it enters major transmission facilities. In B.C., Westcoast Transmission gathers, processes, and delivers gas to provincial LDCs and to Huntingdon for export to the U.S. In the U.S., these services are provided either by the major interstate pipelines or by private companies whose exclusive function is to gather and process gas produced in a certain region for delivery to interstate or intrastate pipelines.

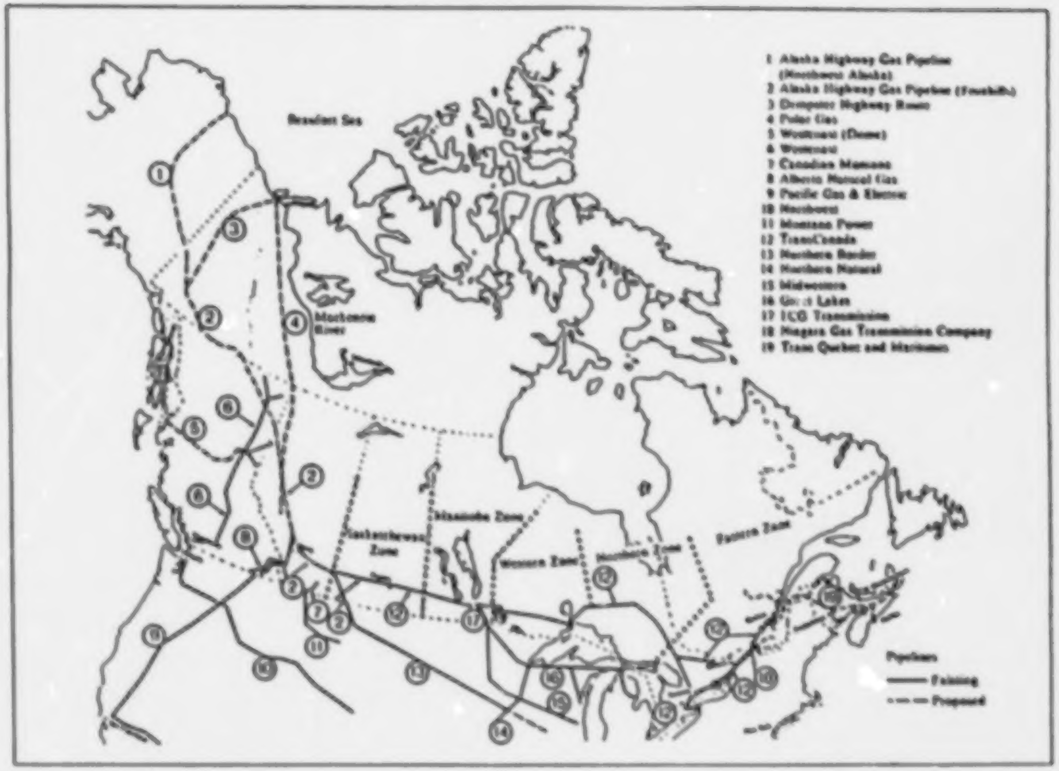
In Alberta, natural gas from gas plants is collected by either the two major LDCs for distribution to Alberta consumers or by NOVA. Producers are responsible for constructing gathering systems and processing facilities and for connecting their processing plants to the various receipt points. NOVA transports the gas to the Alberta border where the remaining NGLs and ethane are removed in straddle plants. The resulting dry gas is then exported from the province by three pipeline companies.

Figure 3.1 illustrates the current Canadian pipeline network, the major export points, and the major U.S. importing pipelines. Most gas exported from Alberta is transported by three different pipelines: Alberta Natural Gas (ANG), Foothills, and TransCanada Pipeline (TCPL). A small amount leaves the province via Westcoast while some is exported directly to Montana. ANG carries gas to Kingsgate where it is purchased by the Pacific Gas and Electric Company and transported by Pacific Gas Transmission for use in the Northern California market.

The Foothills system transports gas to the U.S. border through two legs. The eastern leg delivers gas to the Saskatchewan/U.S. border where Northern Border takes possession for delivery to a number of different interstate pipelines serving markets in the Northwest Central and East-North Central regions. The western leg carries gas via loops on the ANG line to Kingsgate where it is ultimately sold to the Pacific Interstate Transmission Company for delivery into Southern California. These facilities are often referred to as the prebuild system and were built to move Canadian exports until such time as Alaskan gas became available through the Alaskan Natural Gas Transportation System (ANGTS).

TCPL carries Alberta gas to LDCs and direct sales customers in Saskatchewan, Manitoba, Ontario, and Quebec. In addition, it serves two major export points on the U.S. border, Emerson and Niagara, and a number of smaller ones. Gas delivered to Emerson is collected by Great Lakes and Midwestern pipelines for use in the East North Central region and for re-import by Great Lakes near Sarnia, Ontario. Gas delivered at Niagara is collected by Tennessee Gas Transmission for use in the New England region. In the U.S., over 30 interstate pipelines perform TCPL's function of carrying gas across state borders from the major

Figure 3.1
The Canadian Pipeline Network


Beaufort Sea
Mackenzie River
Saskatchewan Zone
Manitoba Zone
Western Zone
Northern Zone
Eastern Zone
1 Alaska Highway Gas Pipeline (Northwest Alaska)
2 Alaska Highway Gas Pipeline (Foothills)
3 Dempster Highway Route
4 Polar Gas
5 Westcoast (Dome)
6 Westcoast
7 Canadian Montana
8 Alberta Natural Gas
9 Pacific Gas & Electric
10 Northwest
11 Montana Power
12 TransCanada
13 Northern Border
14 Northern Natural
15 Midwestern
16 Great Lakes
17 ICG Transmission
18 Niagara Gas Transmission Company
19 Trans Quebec and Maritimes
Pipelines
Existing
Proposed

SOURCE: Economic Council of Canada, 1985, pp. 58.

producing regions to consuming regions. Intrastate pipelines transport gas produced within a state to end-users residing in the same state.

The final stage in the transportation network is the delivery of gas to the burner-tip or end-user. This task is fulfilled by LDCs who take gas from their supplying pipeline and transport it to end users in their service region.

3.2.1.1 Transportation Rate Determination and Current Costs

The pipeline industry is essentially a natural monopoly because of economies of scale and formidable barriers to entry in the form of high capital requirements and risk associated with new pipeline construction. Moreover, the cost of transporting natural gas from the wellhead to the city gate can make up a large portion of the final delivered price, especially in markets situated a great distance from the supplying region. It is the responsibility of the National Energy Board (NEB) in Canada, and the Federal Energy Regulatory Commission (FERC) in the U.S. to monitor and approve these transportation costs and ensure that they are nondiscriminatory. Both agencies are also responsible for approving facilities construction and/or expansions and changes in pipeline transportation rates.

Transportation rates are generally derived by determining an overall cost to a pipeline of providing service (cost of service) and dividing this cost by the total units of transportation and sales service. The cost of service is derived by including such factors as a reasonable rate of return on the pipeline's rate base, which includes the cost of facilities used to provide services (net of depreciation), working capital, and expenses including depreciation, taxes, amortization and depletion.

Pipelines offer a variety of many services to both their sales and transportation customers, including interruptible or firm sales and transportation service, storage, and gathering. Interruptible service differs from firm service in that an interruptible shipper cannot "demand" service if capacity is not available; whereas, if the shipper has firm service, the capacity is reserved for that shipper. Once the cost of service has been determined, it is generally allocated to each of the above services.

The next step is to determine how fixed costs (those costs that do not vary with throughput) will be recovered from the various classes of customers being served by the pipeline. Fixed and variable costs are allocated to either a demand or commodity component. There are four basic methodologies for allocation:

- the "Atlantic Seaboard" methodology in which 50 percent of transmission and storage fixed costs and all "as billed" demand charges are allocated to the demand component. All remaining fixed costs and variable costs are allocated to the commodity component;
- the "United" methodology in which 25 percent of transmission and storage fixed costs and all "as billed" demand charges are allocated to the demand component. All remaining fixed and variable costs are allocated to the commodity component;
- the "Modified Fixed Variable" methodology in which all transmission fixed costs except return on equity and taxes are placed in the demand charge. All variable costs plus return on equity and taxes are placed in the commodity component; and
- the "Full Fixed Variable" methodology which is very similar to the modified fixed variable design except that return on equity and taxes are placed in the demand component.

Presently, the FERC favours the Modified Fixed Variable methodology while the NEB employs the Full Fixed Variable methodology in rate design. This difference has led to the FERC's issuance of Order No. 256 which prevents U.S. pipelines from passing on Canadian exporters demand changes on an "as billed" basis to their customers (discussed in more detail in Chapter 5).

Transportation rates may be formulated differently depending on the configuration of the pipeline. For example, some pipelines charge a "mileage-based" rate under which pipeline miles between the receipt and delivery point are determined and applied to the volume transported. Other pipelines charge "postage stamp" rates under which all transportation service is provided at the same rate regardless of the distance involved. A variation of these two rates is the "zoned" rate structure (currently used by TCPL) under which transportation in or through a particular zone is charged a "postage stamp" rate regardless of the mileage utilized within the zone. Generally, interruptible rates consist only of a commodity charge that equals firm rates at 100 percent load factor. The demand charge generally reflects the cost to the pipeline of reserving capacity for firm shippers. It should be noted that in the U.S. interstate pipelines are allowed to discount rates within a band set by the FERC. Rate discounting is allowed where, for example, lower rates are required to retain fuel switching end-users as long as it does not involve the pipeline recovering lost revenue from other customers (i.e., cross-subsidization).

Table 3.1 shows current transportation costs in Canada. For consumers at the Toronto city gate, the cost of transportation makes up greater than one quarter of the delivered cost if gas is purchased at the Alberta border for $3.00 per Mcf. Moreover, if gas is purchased at less than 100 percent load factor, this cost will increase almost linearly with the declining load factor.

The ability of the natural gas industry to deliver gas to end-users is constrained by two factors--the productive capacity of the natural gas resource base and the volumetric capacity of the natural gas distribution network. In the latter case, there are two types of expansion possibilities--the expansion of existing facilities and the construction of new facilities. Existing facilities can be expanded at relatively low cost by adding compression and looping on existing pipelines. If a new producing region must be connected to demand centers or if sufficient demand exists in a certain region, new facilities may be required.

A tremendous amount of planning must be carried out before construction on a new pipeline can begin. Environmental concerns about pipeline routes and their impact on wildlife and local residents must be addressed. Detailed engineering studies must be done to design and maximize facility efficiency. Capital and operating costs must be estimated and market studies performed to determine if the pipeline throughput will be sufficient for competitive tariffs to be charged. An adequate supply of gas must exist to satisfy demand over the anticipated life of the project and complex financial arrangements are often necessary to satisfy the large capital requirements of major pipeline projects. Throughout this process, constant interface is required with the pertinant regulatory bodies. No pipeline project can proceed without final approval from the regulatory agencies in the particular jurisdiction.

TABLE 3.1
CURRENT TRANSPORTATION COSTS IN CANADA[a]

	Pipeline	Destination	Cost ($Cdn. per Mcf)
Alberta fieldgate	Nova[b]	Alberta City Gate	0.25
Alberta fieldgate	Nova	Alberta Border	0.17
Alberta Border	TCPL	Saskatchewan	0.19
Alberta Border	TCPL	Manitoba	0.35
Alberta Border	TCPL	Western Zone	0.59
Alberta Border	TCPL	Northern Zone	0.92
Alberta Border	TCPL	Eastern Zone	1.16
Alberta Border	TCPL	Emerson (Export)	0.39
Alberta Border	TCPL[c]	Niagara (Export)	1.15
Alberta Border	Foothills	Kingsgate (Export)	0.22
Alberta Border	Foothills	Monchy (Export)	0.22
B.C. Wellhead	Westcoast[d]	B.C. Fieldgate	0.10
B.C. Fieldgate	Westcoast	Pacific Northern	0.04
B.C. Fieldgate	Westcoast	Island Natural	0.10
B.C. Fieldgate	Westcoast	B.C. Hydro	0.19
B.C. Fieldgate	Westcoast	Huntington (Export)	0.19

SOURCE: Canadian Energy Research Institute.

[a] Transportation costs for firm service at 100 percent load factor. Effective date: September 1987.

[b] This is a maximum rate. Intra Alberta transportation is a mileage based rate equal to $0.10/Mcf/100 miles. Interruptible is the same rate but with a maximum charge equal to $0.19/Mcf.

[c] There are four exit points at Niagara. This is the cost to Niagara, Boundary.

[d] Westcoast also charges for liquid recovery service, gathering and sulphur treatment.

3.2.2 The Oil and Gas Exploration, Development, and Production Process

One of the distinguishing features of the upstream petroleum industry is the high degree of risk involved in the exploration process. Exploration is the process by which new natural gas and oil discoveries are added to a producer's inventory of reserves. Although oil and gas coexist in many reservoirs and are often produced together, it is generally accepted that an explorationist intends to find either of the two petroleum products when conducting an exploratory program.

Exploration drilling is divided into five different types of exploratory wells according to the Lahee classification scheme:

- a new field wildcat is a test drilled to locate oil or gas in a region that has not previously produced either hydrocarbon;
- a new pool wildcat is a test drilled to locate a new pool in a region known to contain oil or gas, but outside the known limits of the producing area;
- a deeper pool test is a test drilled within the productive area of a partially or wholly developed pool, or group of pools to explore for deeper unknown prospects;
- a shallower pool test is similar to a deeper pool test but is looking for a pool that is shallower than a known group of productive pools; and
- an outpost is a test drilled with the expectation of extending for a considerable distance the productive area of a partially or wholly developed pool, or pools.[1]

The riskiness of exploration activity in general is illustrated in Table 3.2, which shows the success rates for the different types of exploratory wells drilled in Canada in 1985. New field wildcats are by far the riskiest class of exploratory well, with a success rate across total Canadian wells of 30 percent in 1985. By way of comparison, the success rate for U.S. new field wildcats was 13 percent.[2] The premium for this type of exploratory activity is a greater potential return in terms of the size of the potential discovery. The other classes of wells are drilled in more established areas, so that the chances of discovering a large pool which had escaped previous attention are smaller.

TABLE 3.2
RISKINESS OF CANADIAN EXPLORATION ACTIVITY IN 1985 BY LAHEE WELL CLASS

Class	Success Rate[a]
New Field Wildcat	0.296
New Pool Wildcat	0.512
Deeper Pool Tests	0.632
Shallower Pool Tests	b
Outposts	0.676

SOURCE: Canadian Petroleum Association, Statistical Handbook.

[a] Success Rate calculated as total producing wells over total number of wells drilled.

[b] No shallower pool tests were drilled in 1985.

The nature of the exploratory process demands substantial investment funds before a tangible asset, if any, is realized. Companies must acquire land holdings on which to conduct their drilling programs (this provides them with the right to drill, not surface ownership). This decision occurs very early in the process and is based on the geologic evaluation of the possibility that the underlying rock structure contains either crude oil or natural gas deposits. Firms must bid on these holdings and in theory, in a competitive market with perfect knowledge, the cost of the lease should equal the value of the resource less the cost (including a normal profit) of discovery, development, production, taxes, and royalties. Unfortunately, knowledge or foresight is never perfect and often nothing is found.

Once the desired amount of geological evaluation has been undertaken, the next decision is to drill an exploratory well. If lease conditions do not require drilling to commence in a short time, it is often more profitable to wait for adjoining leases to be drilled first. Since drilling is the major component of the exploratory budget, if reserves are discovered nearby this knowledge can help avoid dry hole costs and can direct drilling efforts. Alternatively, since the expected value of the lease will have increased, the property could be sold for a profit. However, someone must drill first and, as indicated above, there is only a small probability of success. Even if the well is successful, an economic evaluation of the prospect may not justify additional drilling. Given that the exploration costs are sunk, the incremental costs of producing a one-well field might offer a chance for partial cost recovery, but the drilling of the well might not have been justified given prior knowledge of the field size and quantity.

If tests on the discovery well prove promising, a decision to drill a step out, confirmation, or delineation well must be made. These wells are drilled to determine the size of the discovery. Other wells may also be drilled to look for additional reservoirs in the area. A discovery may result in the initiation of a play by increasing the expected value of prospects over a broad area extending beyond the area of the new field.

Finally, after the discovery has been made and additional exploratory wells have been drilled, development and production decisions must be made. The high degree of risk that was present at the beginning of the process has at this point largely been resolved. However, some risk remains. Development wells, which are drilled to the depth of a known productive horizon, had an 89 percent success rate in 1985 for total Canadian wells. Production equipment and well-spacing decisions must be made on the basis of the reservoir's characteristics, the economics of potential production rates, market conditions, and conservation laws and regulations. In general, the development of an individual field is a dynamic process with reserves estimates being constantly revised in light of new production and drilling data and with some wells being abandoned and others completed to maintain an optimal production stream.

3.2.2.1 Above-Ground Versus In-Ground Costs of Natural Gas

The nominal value of the revenue a producer receives at the wellhead must exceed the nominal value of discounted exploration and development costs for the investment to break even. The differential arises because the schedule of costs incurred and revenue received over the project lifetime differ. As mentioned above, most costs are incurred before production begins. Revenue is not received initially, but rather over the life of the project. This general pattern of upfront costs followed by revenue streams makes reserves in the ground worth less than produced reserves at the surface.

Thus, the uniform constant dollar wellhead price (net of royalties) that a producer receives must exceed the average cost of discovery and development per unit of gas in order to generate a stream of revenue over time, whose present value at least equals the present value of cost expenditures measured at the same point. If there are no above normal profits, the cost of resources will just equal what those resources are worth in the ground. Utilizing these assumptions, a simple relationship between above-ground and in-ground value can be developed (see Appendix D). The relationship is given by:

$$P_a = [1 + (i/a)]*P_b$$

where P_a is the above ground value, P_b is the in-ground value, i is the discount rate and a is the reserves decline rate, approximated as the ratio of current production to current reserves. If gas cannot be sold for at least $[1 + (i/a)]$ times the average cost incurred to find and develop it, it is not financially worthwhile to discover gas.[3]

Table 3.3 details some assumptions for typical U.S. and Canadian gas production and compares the ratio of above-ground to in-ground values. The results indicate, perhaps surprisingly, that given similar discount rates and gas costs, Canadian producers must receive 3.5 times the cost of discovering the gas, compared to 2 times cost in the U.S., in order to make the discovery process financially worthwhile. This is illustrative of the cost of holding gas in the ground as inventory and is, in part, due to the pernicious effect of the mandatory surplus rules in Canada and the rapid rate at which U.S. gas reserves are being produced. Essentially, as reserves are depleted more rapidly, the time required to recover capital costs decreases, allowing a lower acceptable wellhead price.

TABLE 3.3
CANADIAN AND U.S. ABOVE-GROUND TO IN-GROUND RATIOS

	Discount Rate	Decline Rate[a]	Above-ground to In-ground ratio
U.S.	10%	.10	2.0
Canada[b]	10%	.04	3.5

SOURCE: U.S. Energy Information Administration, "U.S. Crude Oil, Natural Gas, Natural Gas Liquids Reserves" and CPA Statistical Handbook.

[a] Decline rate calculated as production/reserves.

[b] Canada's decline rate estimated as Alberta reserves/Alberta production.

The impact of higher discount rates can also be illustrated. As the discount rate rises, the cost of holding gas in the ground is increased and the present value of the investment is reduced. The result is an increase in the minimum acceptable price, all other variables held constant. As an aside, firms evaluating an exploration prospect prior to drilling are likely to discount future profits at a high rate, to account for the riskiness of exploration. After a discovery has been made, the project may be re-evaluated at a lower discount rate to reflect the decline in project risk. As a result, the minimum acceptable price could be lower after discovery than that perceived prior to discovery.

Given a competitive market and all other variables held constant, higher prices will increase the per-unit cost producers are willing to incur to find and develop new and existing reserves.

3.3 Conventional Natural Gas Reserves

3.3.1 Canadian Gas Reserves

Nearly all of Canada's conventional natural gas reserves are contained in the Western Sedimentary Basin. The Basin extends from Northeastern B.C. to cover nearly all of Alberta and the southern half of Saskatchewan. Within the Basin, gas is contained in a wide variety of plays, differing according to the depth of pools in the play, the quality of gas, average pool size, remoteness, etc. The Northeast portion of B.C. and the Foothills region of Alberta are dominated by fairly large, deep gas fields containing substantial NGL and sulphur reserves. Drilling costs in these regions are higher than average because of the greater depths, higher logistics costs, and hard rock formations in the Foothills area.

Plays attracting interest in the Northwest region of Alberta are generally characterized by medium to deep pools containing wet (NGL rich) gas. Drilling costs in the Northwest region are generally not as high as in the Foothills region because of better logistics and shallower drilling depths. In the West Central region of Alberta gas tends to be found in medium-depth pools, although the gas does not tend to be as rich in NGLs as gas found in the Foothills or Northwest regions. The Southeast region of Alberta and Southern Saskatchewan are dominated by shallow gas fields containing dry (no NGLs) gas. Drilling costs are substantially lower in this region due to the shallowness of the gas bearing formations.[4]

According to the Canadian Petroleum Association (CPA), in 1986 Canada's conventional areas contained remaining established reserves of 2108 billion cubic metres (74.4 Tcf). Over 83 percent of these reserves, 1750 billion cubic metres (61.2 Tcf), are located in the province of Alberta. Net production from Alberta reserves in 1985 was 68.4 billion cubic metres (2.41 Tcf), about 89 percent of total Canadian net production. British Columbia and Saskatchewan had remaining established reserves in 1986 of 240.3 billion cubic metres (8.5 Tcf), about 11.6 percent of total reserves, and 61.3 billion cubic metres (2.2 Tcf), about 3.0 percent of total reserves, respectively. Production from B.C. and Saskatchewan reserves in 1986 was 6.93 billion cubic metres (245 Bcf) and 1.68 billion cubic metres (59.3 Bcf), respectively, accounting for only 11.0 percent of total Canadian production. If no reserves were added in the future and if existing production levels were maintained, Canada's conventional reserves base would last about 27 years.[5]

Table 3.4 presents the remaining established reserves of marketable natural gas, net production, and reserves life indices for Alberta and British Columbia on an annual basis for the period 1970-1986. Reserves estimates have fluctuated considerably over the period. British Columbia reserves declined from a peak of 288.6 billion cubic metres (10.2 Tcf) in 1970 to 202.7 billion cubic metres (7.15 Tcf) in

TABLE 3.4

REMAINING ESTABLISHED RESERVES AND PRODUCTION IN ALBERTA AND BRITISH COLUMBIA

(billions of cubic metres)

Year	Remaining Reserves	Net Production	R/P Ratio
Alberta			
1966	1123.5	25.25	44.5
1967	1152.4	27.18	42.4
1968	1244.0	31.11	40.0
1969	1300.1	35.11	37.0
1970	1341.7	42.16	31.8
1971	1386.9	45.02	30.8
1972	1360.4	50.96	26.7
1973	1388.7	51.91	26.8
1974	1398.8	54.26	25.8
1975	1442.6	55.42	26.0
1976	1443.2	61.01	23.7
1977	1453.8	59.91	24.3
1978	1549.7	56.56	27.4
1979	1646.4	63.44	26.0
1980	1661.4	61.22	27.1
1981	1723.1	58.62	29.4
1982	1728.4	61.04	28.3
1983	1744.8	55.41	31.5
1984	1898.8	71.55	26.5
1985	1827.1	72.91	25.1
1986	1750.0	68.36	25.6
British Columbia			
1966	232.1	5.00	46.4
1967	251.3	5.73	43.9
1968	251.1	6.78	37.0
1969	251.4	7.28	34.5
1970	288.6	7.13	40.5
1971	282.1	7.95	35.5
1972	268.5	10.16	26.4
1973	257.8	10.74	24.0
1974	222.6	11.04	20.2
1975	210.3	9.18	22.9
1976	202.7	8.46	24.0
1977	210.8	8.61	24.5
1978	218.4	7.43	29.4
1979	207.4	8.50	24.4
1980	208.7	6.69	31.2
1981	222.3	6.95	32.0
1982	220.6	6.80	32.4
1983	222.2	5.62	39.5
1984	224.0	5.86	38.2
1985	243.5	6.28	38.8
1986	240.3	6.93	34.7

SOURCE: Canadian Petroleum Association Statistical Handbook, 1985.

1976 before increasing fairly steadily to 240.3 billion cubic metres (8.5 Tcf) in 1985. Alberta reserves have generally increased over time, from 1443 billion cubic metres (50.9 Tcf) in 1975 to 1899 billion cubic metres (67.0 Tcf) in 1984, before declining slightly in 1985 and 1986 to 1750 billion cubic metres (61.2 Tcf).

Natural gas production has also tended to increase over time. Alberta net production increased through the beginning of the period from 42.2 billion cubic metres (1.49 Tcf) in 1970, to a peak of 72.9 billion cubic metres (2.57 Tcf) in 1985. Production subsequently declined by 4.56 billion cubic metres (0.16 Tcf) in 1986. British Columbia net production has declined considerably over time from 11.0 billion cubic metres (.388 Tcf) in 1974 to 6.28 billion cubic metres (0.222 Tcf) in 1985 due largely to declining exports to the U.S. With few exceptions, the reserves life index for both Alberta and B.C. has remained above 25 over the period 1970-1986.

Natural gas liquids are important and valuable by-products in the production of natural gas. Table 3.5 presents Canada's remaining established reserves of NGLs, net production, total reserves additions, and reserves life index for the period 1970-1986. Extremely large reserves additions in 1984 and 1985 offset a persistent decline in reserves from 1970 through 1983. Net production peaked in 1973 and 1974 at about 17.5 million cubic metres annually (302 Mb/d) and declined to 10.5 million cubic metres (180 Mb/d) in 1983 before increasing to 15.0 million cubic metres (257 Mb/d) in 1986.

Perhaps the most useful indicators of a region's ability to support sustained natural gas production are the annual additions to established reserves and the rate at which these reserves are being added per unit of drilling activity (i.e., the finding rate). The CPA classifies reserves additions into three categories:

- negative and positive revisions--which result primarily from re-evaluation of existing reserves in light of new production and drilling data or changing market conditions;
- extensions--which are additions to previous discoveries and are primarily due to development drilling; and
- discoveries--which are new reserves arising primarily from exploratory drilling.

TABLE 3.5

REMAINING RESERVES AND NET PRODUCTION OF NATURAL GAS LIQUIDS IN CANADA

(millions of cubic metres)

Year	Remaining Reserves	Net Production	Reserve Additions	R/P Ratio
1970	286.3	12.53	21.64	22.8
1971	258.8	13.45	-14.01	19.2
1972	249.9	16.46	7.39	15.2
1973	237.8	17.77	5.65	13.4
1974	246.7	17.24	26.17	14.3
1975	241.7	16.86	11.85	14.3
1976	238.8	16.83	13.88	14.2
1977	227.5	17.94	6.67	12.7
1978	229.7	13.06	15.22	17.6
1979	207.0	13.39	-9.23	15.5
1980	203.1	13.10	9.21	15.5
1981	193.8	12.17	2.82	15.9
1982	198.0	11.39	15.58	17.4
1983	202.8	10.45	15.25	19.4
1984	252.9	14.42	64.36	17.5
1985	320.8	14.90	82.75	21.5
1986	338.8	14.99	33.02	22.6

SOURCE: Canadian Petroleum Association Statistical Handbook, 1985.

Annual additions to Alberta and British Columbia established reserves over the period 1970-1985 are illustrated in Figure 3.2. The uncertain and risky nature of the exploration process is reflected in the volatility of reserves additions over time. Gross additions to Alberta reserves have varied from -6.88 billion cubic metres (0.243 Tcf) in 1972 to 225.6 billion cubic metres (7.96 Tcf) in 1984 to -8.71 billion cubic metres (-0.31 Tcf) in 1986. Average annual gross additions for the period 1970-1977 were 69.3 billion cubic metres (2.45 Tcf), compared to 92.5 billion cubic metres (3.30 Tcf) for the period 1978-1986. This upswing in reserves additions becomes more prominent if one considers that in 1985 and 1986 only 1155 million cubic metres (0.04 Tcf) and -8.705 million cubic metres (-.31 Tcf), respectively, were added to established reserves.[6]

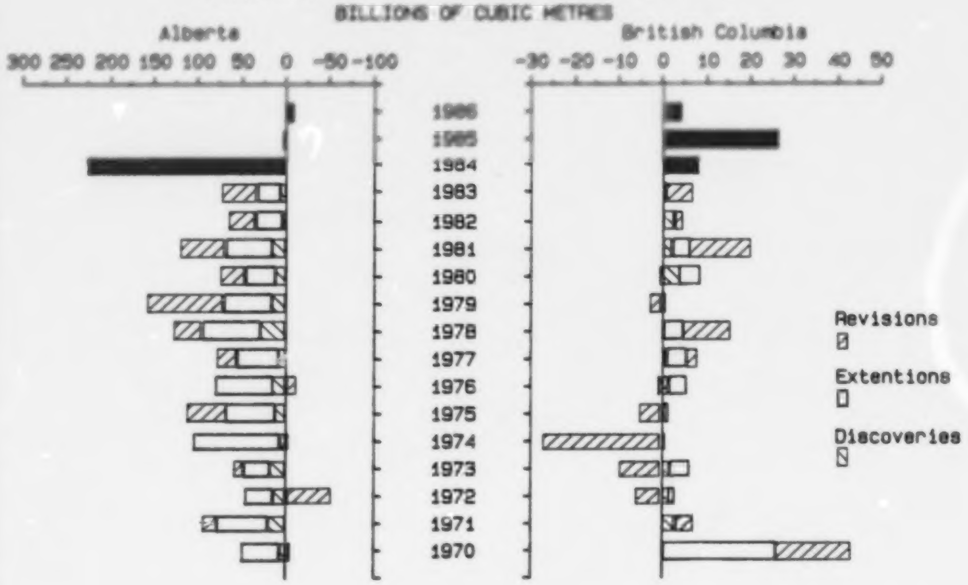
British Columbia's statistics indicate the same volatility. During the period 1970-1986, 4 years of negative gross reserves additions can be observed. These negative additions result from a combination of overly optimistic reserves estimates of prior discoveries and new data on reservoir characteristics. From 1976-1986, no negative additions were recorded and annual reserves additions averaged 9.9 billion cubic metres (0.351 Tcf).

Finding rates are widely used to indicate trends in exploration and development drilling success. Essentially, the finding rate is calculated as reserves added due to drilling activity divided by some measure of that activity. There are a number of problems inherent in this definition. Perhaps the most difficult problem is the allocation of reserves additions to particular types of drilling activity and to the year in which the actual drilling took place. New discoveries tend to appreciate over time due to subsequent infill and/or development drilling, increased knowledge of reservoir characteristics, and so on. Furthermore, one can only divide unsuccessful drilling activity between oil and gas on an adhoc basis. For these reasons one must carefully specify the chosen methodology and regard the results as evidence of broad trends.

We estimate finding rates as reserves additions due to extensions and discoveries divided by successful development and exploratory wells drilled in that year. Using this approach, we avoid the problem of allocating unsuccessful activity. Figure 3.3 shows gas directed drilling activity in Alberta and B.C. from 1970-1986 and distinguishes between exploratory and development drilling. Total successful gas well completions peaked between 1976 and 1980 as a result of high

Figure 3.2

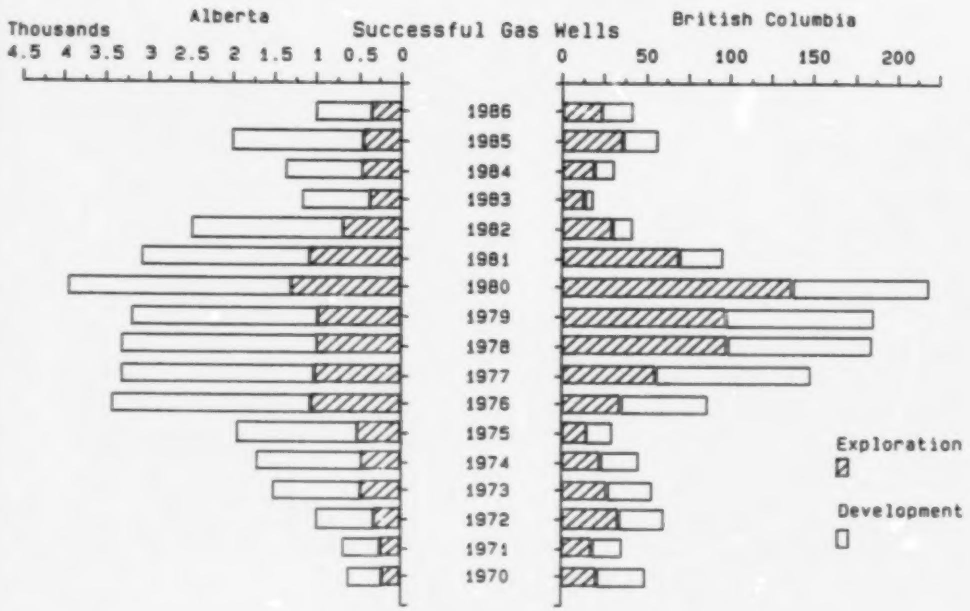
Reserves Additions in Alberta and British Columbia



SOURCE: Canadian Petroleum Association, Statistical Handbook.
NOTE: Data from 1984 is for gross reserve additions, the sum of these categories.

Figure 3.3

Drilling Activity in Alberta and British Columbia



SOURCE: Canadian Petroleum Association, Statistical Handbook.

domestic and export gas prices. Gas directed drilling activity has since declined substantially due to low gas prices and excess productive capacity.

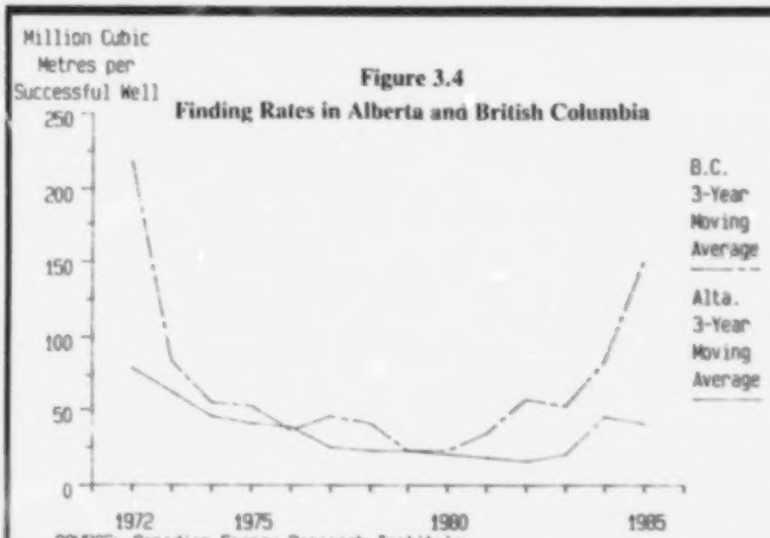
Figure 3.4 plots finding rates in Alberta and British Columbia for the period 1970-1985. The general trends illustrated by the 3-year moving averages are that finding rates peaked in the early 1970s, declined quite sharply through to the early 1980s, and recovered somewhat over the last few years. In Alberta, finding rates averaged 55.0 million cubic metres per successful well (1.94 Bcf/well) through the period 1970-1976 before declining sharply and stabilizing at an average of 26.6 million cubic metres per successful well (0.94 Bcf/well) over the last 9 years. A similar trend is evident in British Columbia where the finding rate averaged about 112.1 million cubic metres per successful well (3.95 Bcf/well) between 1970-1976 and 76.6 million cubic metres per successful well (2.71 Bcf/well) between 1977-1985.

Actual production and the productive capacity of natural gas reserves seldom coincide. Productive capacity is of some interest because it provides an indication of the level of production that might be sustained given sufficient demand. Figure 3.5 compares the productive capacity and actual production from Canada's conventional areas for the period 1970-1981. As illustrated, early in the 1970s conventional reserves were being produced at near capacity. Since 1975, however, production has remained fairly constant while productive capacity has continued to grow at a fairly rapid rate (before declining slightly in 1984 and 1985). As of 1985, the NEB estimates that the excess productive capacity of Canada's conventional reserves approaches 38 billion cubic metres (1.3 Tcf).

3.3.2 U.S. Reserves

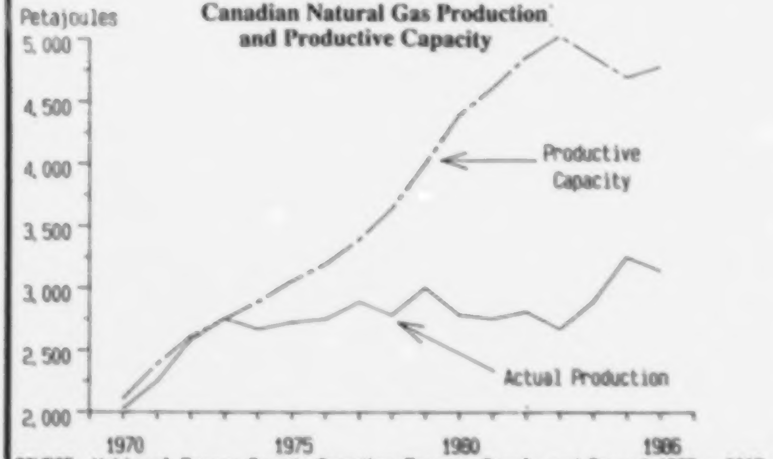
In 1985, U.S. Lower-48 proved reserves of natural gas totalled 4519 billion cubic metres (159.5 Tcf). Gas contained in the fields of Texas (49.0 Tcf) and Louisiana (40.2 Tcf) make up over 46 percent of this total. About 23 percent of total proved reserves are contained in offshore fields. Onshore, the Midcontinent and Rocky Mountain regions have the highest level of reserves. The Anadarko region is dominated by large shallow fields such as the Hugoton field, the largest gas field in the U.S., and the Texas Panhandle fields. Most gas in the Rocky Mountain region is contained in fields ranging in depth from 5,000 to 10,000 feet.

Figure 3.4
Finding Rates in Alberta and British Columbia



SOURCE: Canadian Energy Research Institute.

Figure 3.5
Canadian Natural Gas Production and Productive Capacity



SOURCE: National Energy Board, Canadian Energy, Supply and Demand 1985 - 2005.

Proved reserves of NGLs in the Lower-48 states were estimated to be 7,561 million barrels in 1985. NGLs found in Texas fields made up 39 percent (2,981 million barrels) of this total, while 11 percent are contained in offshore fields.[7]

Although only a very small portion of the natural gas reserves contained in Alaska are being produced, proved reserves in the region were estimated to be 958.8 billion cubic metres (33.8 Tcf) in 1985. The majority of this gas, about 91 percent, is found in associated-dissolved reserves on the Alaskan North Slope. Proved reserves of Alaska NGLs were estimated at 383 million barrels in 1985.

Table 3.6 presents total U.S. proved reserves of natural gas, net production, and the reserves to production ratio for the period 1970 to 1985 (excluding proved gas reserves in Alaska). U.S. proved gas reserves have declined throughout the period from 7498 billion cubic metres (290.7 Tcf) in 1977 to 5478 billion cubic metres (193.4 Tcf) in 1985 despite falling levels of production. The aggregate reserves to production ratio in the Lower-48 states has averaged about 10 years over this period.

The major reason for the decline in proved reserves is that since 1970, annual additions to reserves have consistently failed to replace production. Total annual additions to reserves from 1970-1985 are shown in Figure 3.6. Through the era of low wellhead prices prior to the enactment of the NGPA in 1978, total annual additions to reserves averaged 274.0 million cubic metres (9.68 Tcf) while annual production averaged 516.9 billion cubic metres (18.24 Tcf). Concurrent with the increase in certain wellhead price ceilings in 1978, total additions to reserves increased to 550.3 billion cubic metres (19.4 Tcf) but have since fallen to 337.1 billion cubic metres (11.9 Tcf) in 1985. Natural gas production declined from 533 billion cubic metres (18.8 Tcf) to 453 billion cubic metres (16.0 Tcf) over the same period.

Natural gas discoveries are broken down into three classes; extensions to old reservoirs, new field discoveries, and new reservoir discoveries in old fields. Of these classes, new field discoveries have declined the most, from 93.5 billion cubic metres (3.3 Tcf) in 1977 to 28.3 billion cubic metres (1 Tcf) in 1985. The major source of total discoveries is through extensions to old reservoirs which, on average, make up 60 percent of total discoveries.

TABLE 3.6

U.S. PROVED RESERVES AND PRODUCTION

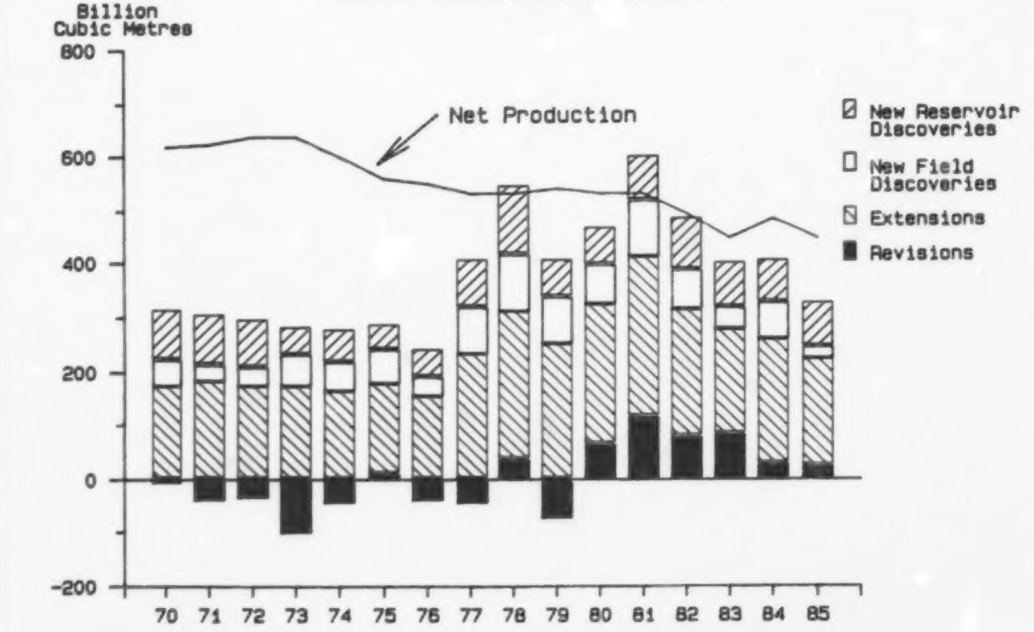
(billions of cubic metres)

Year	Remaining Reserves	Net Production	R/P Ratio[a]
1970	8236.2	622.1	12.1
1971	7897.9	625.4	11.5
1972	7537.6	637.7	10.7
1973	7080.5	640.4	9.9
1974	6717.4	603.9	9.9
1975	6464.4	558.6	10.3
1976	6119.5	551.0	9.8
1977	5875.6	533.8	9.6
1978	5893.1	532.7	9.7
1979	5693.8	545.5	9.1
1980	5637.8	529.7	9.3
1981	5714.6	530.8	9.4
1982	5708.4	495.9	10.0
1983	5672.6	447.2	11.0
1984	5593.7	487.0	10.0
1985	5477.7	452.8	10.5

SOURCE: 1970-1976 American Gas Association, Committee on Natural Gas Reserves, 1977-1984 U.S. Department of Energy, Energy Information Administration.

[a] Reserve to production ratios exclude 26 trillion cubic feet in Prudhoe Bay, Alaska discovered in 1968.

Figure 3.6
Reserve Additions in the United States



SOURCE: 1970–1976–American Gas Association, Committee on Natural Gas Reserves
1977–1984–U.S. Department of Energy, Energy Information Administration

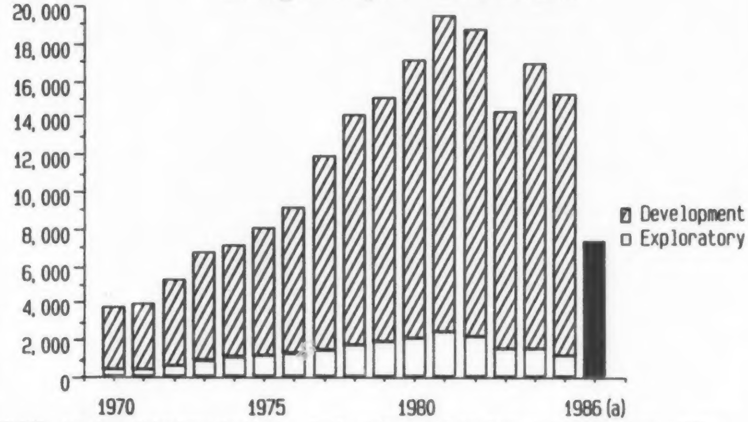
An interesting point of comparison between Canadian and U.S. reserves is the finding rate. Figure 3.7 shows gas directed drilling activity in the U.S. as indicated by successful gas well completions. Following the increase in wellhead price ceilings in 1978 and concurrent with increasing oil prices between 1978 and 1982, total successful gas completions increased from 12,119 in 1977 to a peak of 19,742 in 1981. Total completions have declined substantially to 7,280 in 1986, due to lower wellhead prices and excess productive capacity.

Finding rates in the U.S., illustrated in Figure 3.8, have not shown the same volatility evidenced in Canada although there has been a pronounced downward trend. Reserves added per successful well have declined from 83.4 million cubic metres per well (2.95 Bcf/well) in 1970 to 20.5 million cubic metres per well (0.72 Bcf/well) in 1985. Over the last 9 years, finding rates in the U.S. have averaged 25.9 million cubic metres per well (0.91 Bcf/well) compared to an average of 26.6 million cubic metres per well (0.94 Bcf/well) in Alberta.

Production levels in the U.S. vary considerably by region and depth. The Offshore region is the largest producing region, accounting for over 33 percent of 1982 gas field production. In the same year, the Midcontinent region produced the largest volume of shallow gas; Southern Texas and the Offshore region produced the largest volume of gas between 5,000 and 10,000 feet; the Offshore region produced the largest volume of near deep gas (10,000-15,000 feet); and Southern Louisiana, the Midcontinent, and the Southeast produced the largest volume of gas below 15,000 feet.[8]

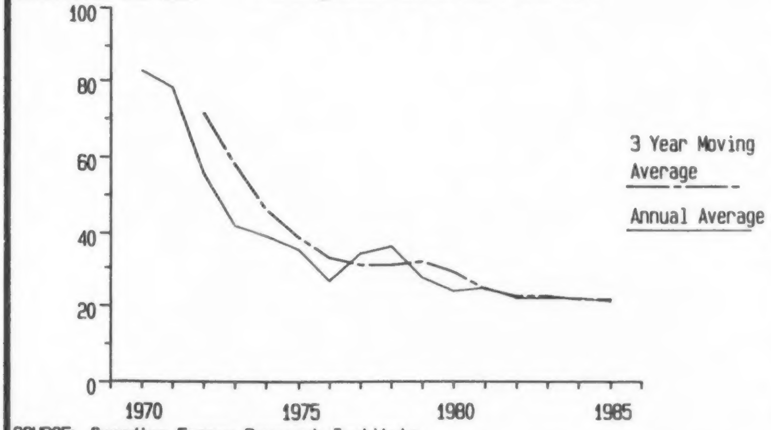
The ratio of reserves to production (the reserves life index) is a fairly good indicator of production rates. Reserves-to-production ratios can vary considerably on a regional basis, depending on local geology and market conditions, as shown in Table 3.7. The Rocky Mountain regions have the highest reserves to production ratio as many fields are not in full production because of a lack of facilities and because of low production rates from the regions low permeability ("tight gas") fields. The Texas and Offshore regions have the lowest reserves-to-production ratios. In the Offshore regions, the high permeability and reservoir pressure of most fields allow gas to be produced at high rates. These high rates are required to allow recovery of the regions' high exploration and development costs.

Figure 3.7
Drilling Activity in the United States



SOURCE: American Petroleum Institute, Basic Petroleum Data Book, Vol.VI, #3, Sept. 1986.
(a) Total completions in 1986 are estimated by the American Gas Association.

Figure 3.8
Finding Rates in the United States



SOURCE: Canadian Energy Research Institute.

TABLE 3.7

U.S. RESERVES-TO-PRODUCTION RATIOS OF NATURAL GAS FIELDS DISCOVERED BETWEEN 1972-1982 BY REGION

Region	Reserves/Production
Northeast	9.5
Southeast	8.3
South Louisiana	11.8
South Texas	7.7
West Texas	7.2
Midcontinent	7.6
Rocky Mountian	17.9
Offshore	6.1

SOURCE: Energy Information Administration Office of Oil and Gas: Crude Oil and Natural Gas Resource Evaluation System (Congress).

The large number of producing fields in the U.S. makes it very difficult to estimate the productive capacity of the nation's reserves. Estimates of the current surplus in productive capacity range from 2 to 4 Tcf. The AGA estimates of productive capacity versus demand are shown in Figure 3.9. They estimate excess productive capacity in 1987 to be 2.5 Tcf. Declining Lower-48 drilling activity, due to depressed prices and higher gas demand, are expected to cause demand and supply to become balanced by 1990.

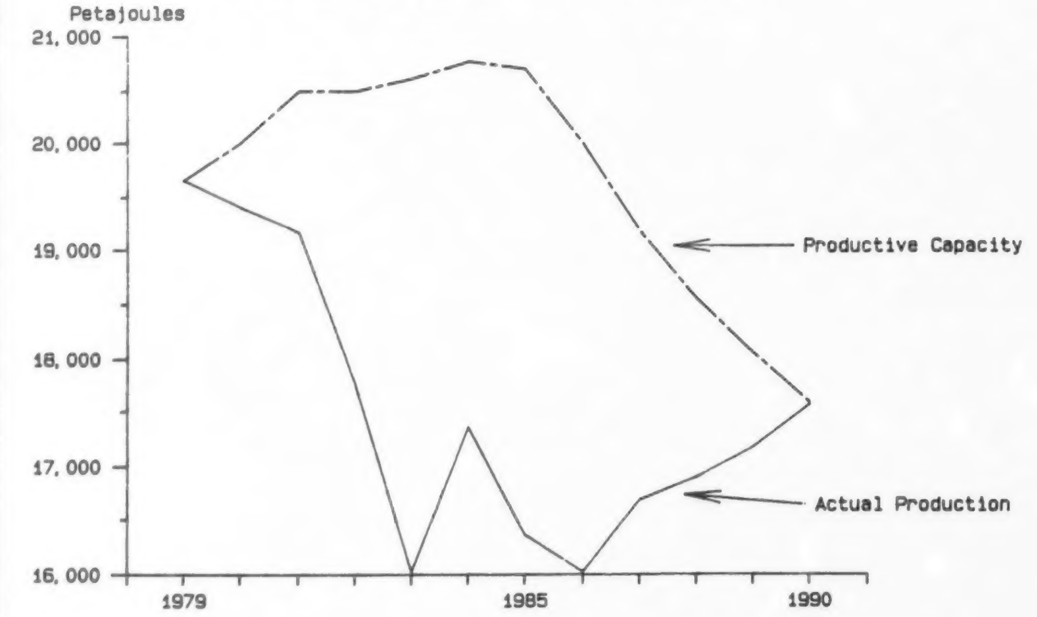
However, as the reserves-to-production ratios indicate, this surplus is largely due to depressed demand rather than excess supply. It is likely that during the next extended cold snap, existing reserves will be called on to produce at their maximum capabilities. The production rates achieved during such a period will perhaps provide the best estimate of U.S. natural gas productive capacity.

3.3.3 Conventional Natural Gas Supply Costs

An important data input to the GRI North American Regional Natural Gas Model is the cost of future reserves additions. This section presents historical estimates of the various components of this cost as required by the model. These estimates provide a useful starting point for the formulation of the resource cost curves. Moreover, because we have estimated these costs for both Canada and the U.S.,

Figure 3.9

U.S. Natural Gas Production and Productive Capacity



SOURCE: American Gas Association.

they provide the basis for a comparison of natural gas supply costs in each country, albeit on an aggregate level.

Natural gas supply costs vary considerably depending on the type of play being considered. Location, depth, reserves, porosity, associated by-products, and other reservoir characteristics all contribute to the variance in these costs and make their analysis a most difficult task. If, however, one wishes to examine broad trends in cost and is willing to pay the price of generality, aggregate statistics can be used. One must, however, understand the limitations of the approach, make clear the assumptions and methodology that are being used, and be careful not to draw sweeping conclusions on the basis of the analysis.

Our approach focuses on the two major components of supply costs: capital and operating costs. Capital costs refer to the expenditures that must be made to find, develop, and connect a natural gas field. Such expenditures include land, geological and seismic work, exploration and development drilling, pumps, compressors, tubing, and gas plant construction costs. Operating costs refer to the costs of lifting the gas out of the ground and processing it to remove associated by-products such as NGLs and sulphur. These costs include fuel, labour, administration, workovers, etc.

3.3.3.1 Capital Costs

It is imperative that the costing methodology be amenable to the use of available data in both countries, so that a rough comparison of supply costs can be made. For Canada, the CPA publishes annual statistics on industry expenditures, reserves, and production. The U.S. Bureau of Census publishes similar data that, unfortunately, is only available from 1973-1983. The estimate of the capital cost component of supply costs consists, therefore, of exploration and development expenditure directed to finding and developing gas pools, divided by reserves additions resulting from that expenditure. Some of the difficulties involved in such a procedure were mentioned in the above discussion of finding rates. To summarize, the major difficulties encountered are:

- the allocation of dry hole expenses between oil and gas;
- the allocation of reserves additions to either exploration or development expenditures;

- the fact that only a small portion of reserves additions are typically booked in the same year that expenditures are made; and

- finally, reserves reported as discoveries in any one year seldom remain unchanged through time--estimates are constantly being revised as more information is obtained from production data and additional development drilling.[9]

While there is no way to avoid the above problems, one must choose a methodology that minimizes the distortions they will cause.

There are essentially two approaches to estimating the capital cost component of supply costs. The first, which has been utilized extensively by CERI, relates exploration costs in a given year to the reserves found in that year as fully appreciated in subsequent years.[10] It is argued that to relate annual reserves additions to that year's exploration costs would overestimate the finding costs by underestimating the true size of the reserves. For our purposes, however, this approach is not suitable as it focusses strictly on finding costs and ignores the development costs which are required to prove up the pool.

An alternative approach, developed by Eglington and Uffelman, relates exploration plus development costs in a given year to reserves additions in that year.[11] As this methodology incorporates development costs, as required in the natural gas model, it is utilized in this analysis. Our methodology is a simplified version of their approach, designed to allow broad comparison between Canadian and U.S. capital costs, and is summarized as follows:

- capital costs are estimated by relating exploration plus development costs allocated to gas in a given year to reserves additions booked in that year; and

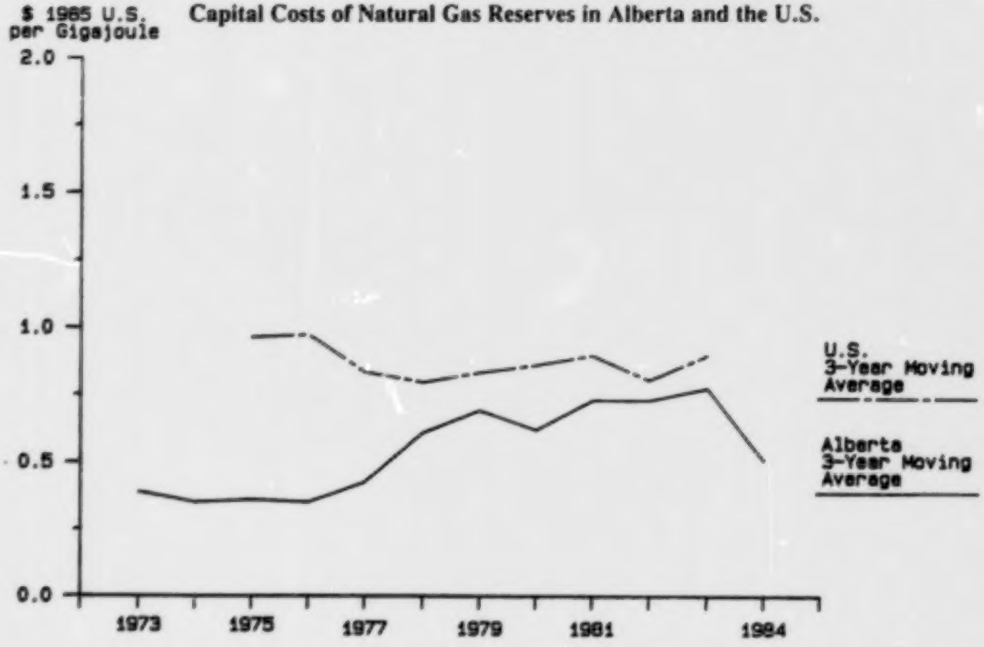
- development and exploration expenditures are allocated to gas according to the ratio of gas well to oil well completions.

A more detailed description of this analysis, the underlying data and a sensitivity analysis of the results is provided in Appendix E.

Figure 3.10 plots the estimated capital costs of natural gas reserves in Alberta and the U.S. To smooth out annual variations and

Figure 3.10

Capital Costs of Natural Gas Reserves in Alberta and the U.S.



SOURCE: Canadian Energy Research Institute.

show longer term trends, we have presented these costs on a 3-year moving average basis. It is apparent that, on average, the cost of natural gas reserves in the United States has consistently exceeded the cost of reserves in Alberta by about 30 percent, supporting the contention of many industry participants that Canadian gas costs are lower than U.S. costs given the prevailing exchange rate. Note that this methodology essentially measures the in-ground cost of natural gas reserves and does not consider the required wellhead price.

3.3.3.2 Operating Costs

The calculation of average production costs is not beset by the difficulties and ambiguities involved in estimating the capital cost component. In each country we have a good estimate of total operating costs which can be partitioned between oil and gas with a tolerable degree of error. It should be remembered that these will be average costs for all wells operating. Operating costs vary substantially by well depending on depth, pool size, number of wells producing a field, productivity, location, etc. However, average costs will allow us to examine and compare broad trends in both countries.

Average Canadian operating costs are estimated for Alberta, B.C., and Saskatchewan using CPA data. Operating expenditures are partitioned between oil and gas on the basis of CPA survey data.[12] Gas allocated expenditures are then divided by annual marketed production to arrive at an estimate of operating costs per Mcf. Adelman and Lynch (1985) take much the same approach with U.S. data, except that U.S. Bureau of Census estimates of annual operating expenditures are allocated to gas according to the ratio of producing gas wells to oil wells. There is an upward bias in this data since a large number of gas wells in the U.S. have been in place for many years and are produced until operating costs approach the wellhead price. At such costs, it would not be feasible to drill another well to develop new reserves. To account for this bias, Adelman and Lynch weight the average production per well in each state by that state's total production. This results in a quintupling of the average production per well, yielding a significant reduction in estimated operating costs per unit of production.[13]

Table 3.8 presents the estimates of per-unit operating costs in both countries. Although there is significant cost variance within both countries, it seems clear that on average, Canadian operating costs are lower than those observed in the United States. It must be

TABLE 3.8

U.S. AND CANADIAN OPERATING COSTS
($1985 U.S. per gigajoule)

Year	U.S.	Alberta	B.C.	Saskatchewan
1973	0.07	0.16	0.08	0.05
1974	0.08	0.16	0.10	0.06
1975	0.10	0.18	0.11	0.06
1976	0.12	0.13	0.08	0.04
1977	0.13	0.08	0.07	0.06
1978	0.14	0.09	0.10	0.08
1979	0.15	0.10	0.11	0.07
1980	0.18	0.11	0.16	0.09
1981	0.27	0.11	0.17	0.08
1982	0.29	0.12	0.19	0.07
1983		0.19	0.21	0.10
1984		0.20	0.23	0.10
1985		0.19	0.25	0.09
1986				

SOURCE: U.S. operating costs from Adelman and Lynch, "Supply Aspects of North American Gas Trade," Table 2. Canadian operating costs from the CPA, Historical Analysis of Industry Operating Costs for Oil and Gas Production in Western Canada.

remembered that these are average costs and are not indicative of the costs of producing new reserves. As production from a field declines over time, operating costs, which remain fairly constant over time, will tend to increase on a per-unit basis.

3.3.3.3 Treatment of By-products

Valuable by-products are produced in conjunction with natural gas. Natural gas liquids (NGLs), which consist of pentanes, propanes and pentanes plus, ethane and sulphur, are removed at various stages in the production and transportation process. NGLs are removed from the raw natural gas in gas plants, sulphur is removed from H_2S rich gas in sour gas processing plants, and most of the ethane is removed in straddle plants after the other NGLs and sulphur have been stripped from the raw gas.

The revenue received from the sale of these products is substantial, making up 23 percent of the value of combined Canadian natural gas and gas liquid sales in 1985. In the same year, investment in gas plants equalled about 28 percent of total gas field development expenditures and 48 percent of total gas related operating costs.[14] Obviously the costs of removing these by-products and the revenue they generate play an important role in the natural gas industry and must be taken into account in the resource cost curves utilized in the regional natural gas model.

A number of approaches can be followed in determining the impact of by-product revenue and costs on natural gas supply costs. Since expenditures cannot be broken down by product and since by-product production and development occur only in conjunction with natural gas production, we will describe gas plant operating costs in terms of marketed natural gas production. The gas plant operating costs are then easily calculated, using CPA data, as operating costs attributable to gas plant operation divided by marketed gas production in that same year. The capital costs of constructing natural gas plants are accounted for by dividing annual capital expenditures by that year's gross reserves additions. This in-ground cost is then converted to above-ground costs using the methodology described in section 3.2 (see Appendix E for the detailed calculation).[15] Revenue received from the sale of by-products is calculated as the combined value of producer sales divided by marketed gas production. The revenue net of capital and operating costs is then expressed as an NGL credit.

These results are provided in Table 3.9 and serve to emphasize the importance of by-product revenue to the economics of the natural gas industry. If one treats the net revenue received from these products as a credit against well operating costs, its impact is to reduce these costs to near zero. In fact, for the years in which oil prices were extremely high (basically 1980-1985) this representation of operating costs would yield a negative cost for gas production.

Revenue obtained from the co-production of sulphur also has a considerable impact on the economics of the Canadian natural gas industry. Prices for sulphur currently range from $110-$130 Cdn./ton.[16] Demand is strong and is anticipated to remain so in the future. Inventory is being drawn down and the price is making otherwise marginal gas plays economic, despite the higher operating and processing costs for these type of plays.[17]

3.4 Canadian Frontier Reserves

As Canada's conventional reserves of natural gas are depleted and export and domestic market potential is realized, more and more attention will be focused on procuring gas from our frontier regions. Exploration to date has resulted in significant discoveries in our Arctic and Eastern Offshore regions. Because of the large discoveries per exploratory well, finding costs are very low. However, high transportation and development costs and a lack of secure markets prevent these reserves from being produced.

3.4.1 Northern Canada

3.4.1.1 Arctic Islands

As of 1985, the CPA considers 406 370 million cubic metres (14.3 Tcf) of the Arctic Islands' discovered resources as established reserves. The Canadian Oil and Gas Lands Administration (COGLA) estimates discovered resources as 415 700 million cubic metres (14.7 Tcf).

These resources are the culmination of exploration activity that commenced in the early 1960s. To date this drilling has resulted in the discovery of some 18 fields containing both oil and gas. Gas fields range in size from 98.5 billion cubic metres (3.5 Tcf) at Drake, 85.5 billion cubic metres (3.0 Tcf) at Hecla, and 57.2 billion cubic metres (2.0 Tcf) at Whitefish, down to about 11.9 billion cubic metres

TABLE 3.9

VALUE OF NATURAL GAS LIQUIDS PRODUCTION

Year	Marketed Gas Production (petajoules)	Total Value of By-product Sales (thousands of dollars)	Revenue/GJ of Marketed Gas Production	Natural Gas Plant Operating Costs (millions of dollars)	Operating Cost/GJ of Marketed Gas Production	Capital Cost/GJ of Annual Reserve Additions	NGL Credit
1976	2 209 322	876,783	0.40	201.4	0.09	0.15	0.16
1977	2 328 603	1,056,027	0.45	240.8	0.10	0.12	0.23
1978	2 291 221	1,071,631	0.47	278.5	0.12	0.10	0.25
1979	2 460 665	1,366,579	0.56	314.3	0.13	0.09	0.34
1980	2 306 456	1,909,454	0.83	354.0	0.15	0.23	0.45
1981	2 301 997	2,313,057	1.00	409.0	0.18	0.19	0.63
1982	2 382 372	2,454,148	1.03	468.5	0.20	0.59	0.24
1983	2 251 461	2,700,065	1.20	492.4	0.22	0.20	0.78
1984	2 445 765	2,946,427	1.20	563.5	0.23	0.06	0.91
1985	2 706 992	2,363,329	0.87	602.8	0.22	20.36	-19.71

SOURCE: Canadian Energy Research Institute (all data taken from the CPA Statistical Handbook, various editions).

(420 Bcf) at Thor. Clearly, some of the largest gas fields in Canada lie in the Arctic Islands.[18]

In 1983, the Geological Survey of Canada estimated the Arctic Islands Region to contain an undiscovered gas potential of 2257 billion cubic metres (79.7 Tcf) with an average degree of confidence and 1100 billion cubic metres (38.8 Tcf) with a high degree of confidence.[19] Since 1978, annual additions to discovered resources have averaged 16 532 million cubic metres (587 Bcf). From 1969 (when drilling commenced on a fairly continual basis) to 1977, annual additions to discovered resources averaged 36 397 million cubic metres (1.3 Tcf) per year.[20] With the demise of the Petroleum Incentives Program (PIP), drilling activity in the Arctic has slowed to a virtual standstill. If, however, drilling activity rebounds due to improved market conditions, the gas potential of the Arctic Islands suggests that anywhere from 0.5 to 1.5 Tcf of gas production could be expected annually over the next 20 years.

3.4.1.2 Mackenzie Delta and Beaufort Sea

Exploration activity began on the land portion of the Mackenzie Delta in the mid-1960s, with Esso, Shell, and Gulf all making significant gas discoveries. Dome Petroleum and Esso have pioneered offshore drilling in the Beaufort Sea. Although a number of gas discoveries have been made, no offshore discovery has been followed by delineation drilling so that it is difficult to provide an estimate of offshore gas reserves.

The CPA estimates established reserves in the region to be 258 310 million cubic metres (9.1 Tcf) in 1985. COGLA estimates discovered resources of gas to be 284 200 million cubic metres (10.0 Tcf) for the same year. The Geological Survey of Canada estimates the regions undiscovered gas potential to be 1865 billion cubic metres (65.8 Tcf) with an average expectation, and 871 billion cubic metres (30.7 Tcf) with a high level of confidence. Fields discovered to date range in size from Issunguak and Taglu, at 70.8 million cubic metres (2.5 Tcf) and 68.0 millon cubic feet (2.4 Tcf) respectively, to Niglintgak at about 22.7 million cubic feet (801 Bcf).[21]

The Polar Gas Pipeline Proposal

The most recent and comprehensive proposal to build a pipeline from these northern fields to connect them into existing transportation facilities is the Polar Gas Pipeline Proposal.[22] The proposal envisages a pipeline route (see Figure 3.11) that will initially connect the land based reserves in the Taglu, Parsons Lake, and Niglintgak Fields with existing pipeline systems at Edson, Alberta. The other fields on land and offshore could be connected at a later date depending on market requirements and economics. An extensive lateral pipeline would be required to connect fields in the Arctic Islands to the Polar Gas System.

The total cost of the pipeline project from Taglu to Edson is estimated to be 3.4 billion dollars (1986 Cdn.). The cost estimate is based on a 36-inch pipeline operating at 1440 psig with a capacity of 0.8 Bcf per day. With additional compressor stations and horsepower additions at existing stations, the capacity of the system could be increased to 1.6 Bcf per day.

The unit cost of transportation from Taglu to Edson, assuming a 100 percent load factor in the first year of operation, is estimated to be $2.50 per Mcf (1986 Cdn.). This cost is expected to decrease quite rapidly after the first year, to about $1.26 per Mcf (1986 Cdn.) within 10 years, if a 100 percent load factor is maintained.

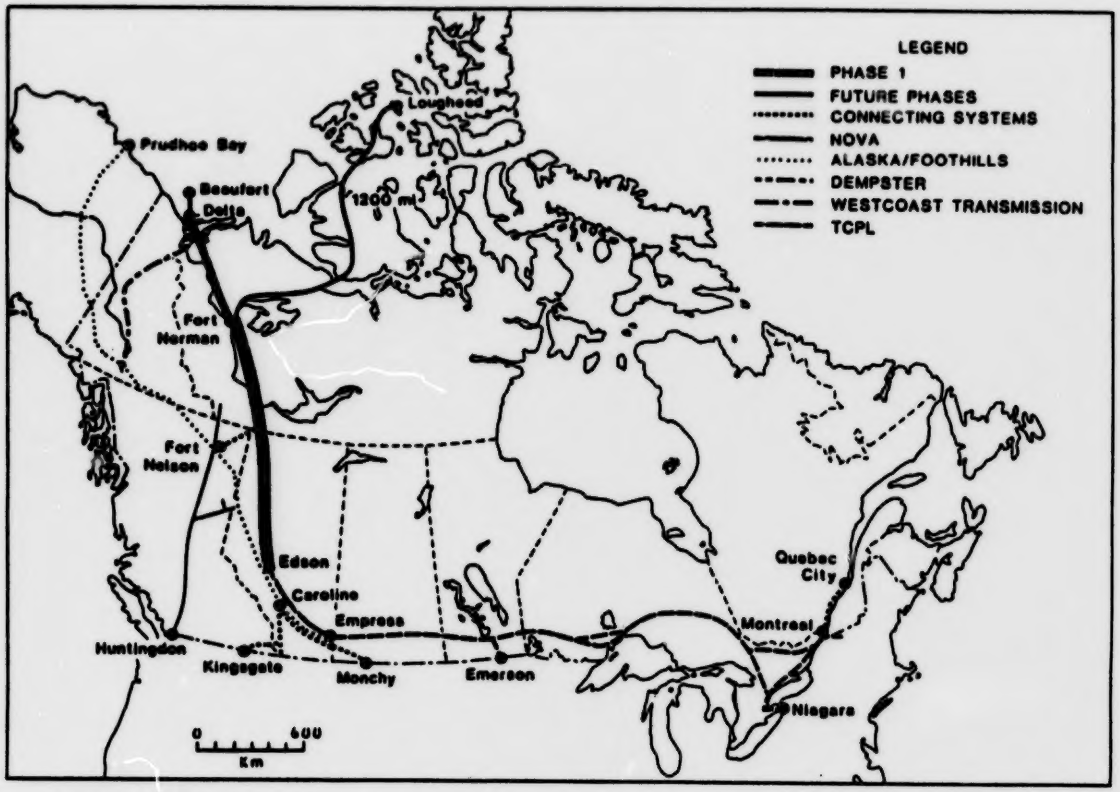
3.4.2 Eastern Offshore

Exploration to date in the Eastern Offshore region has identified several large gas discoveries plus numerous accumulations that are not considered to be economically feasible under current conditions. The CPA does not consider any of these discoveries as established reserves. COGLA estimates discovered resources in the Grand Banks and Labrador Sea at 152.4 billion cubic metres (5.4 Tcf) and offshore Nova Scotia at 127.4 billion cubic metres (4.5 Tcf). The Geological Survey of Canada estimates with an average expectation that the Eastern offshore gas potential is 2423 billion cubic metres (85.5 Tcf). Their high confidence estimate suggests a gas potential of 725 billion cubic metres (25.6 Tcf).[23]

The most promising discoveries in the Grand Banks/Labrador Sea region are the North Bjarai and Bjarni fields. Hostile environmental conditions make year round production very difficult and the proximity of the fields to markets suggest that they will remain a long-term supply alternative. The Hibernia area contains significant associated reserves and it is likely that a large amount will be produced in conjunction with crude oil production when (and if) the Hibernia field is developed. This gas will need to be handled through reinjection

Figure 3.11

Pipeline System: Polar Gas Project


LEGEND
PHASE 1
FUTURE PHASES
CONNECTING SYSTEMS
NOVA
ALASKA/FOOTHILLS
DEMPSTER
WESTCOAST TRANSMISSION
TCPL
Prudhoe Bay
Beaufort
Delta
Loughead
1200 mi
Fort Norman
Fort Nelson
Edson
Caroline
Empress
Huntingdon
Kingsgate
Monchy
Emerson
Montreal
Quebec City
Niagara
0
600
Km

SOURCE: Polar Gas Project, presentation to the House of Commons Standing Committee on Energy, Mines, and Resources, February 10, 1987.

flaring production for sale, or some combination of these methods. Presently the plan is to reinject the gas during the initial production years. It is therefore not likely that transportation or marketing of Hibernia gas will become a reality before the year 2000.

3.4.2.1 The Venture Gas Project

The Venture gas project is a proposal to develop gas fields in the Scotia Shelf region.[24] These fields are located approximately 300 kilometres east of Halifax, Nova Scotia near Sable Island and are the most economically feasible discoveries made in the Eastern offshore region to date. The participants in the project estimate that proved plus probable reserves in the Venture project area, as of April 1, 1985, at 66.81 billion cubic metres (2.36 Tcf). Production rates of 9.05 million cubic metres per day (320 MMcf/d) are expected when production commences. Eight and one-half million cubic metres per day (300 MMcf/d) are expected to be sold to U.S. buyers and up to 0.55 million cubic metres per day (20 MMcf/d) are expected to be available for domestic sales in the Maritimes. The fields also contain significant amounts of natural gas liquids. Liquids production is projected at about 2040 cubic metres per day (12,800 bbls/d) through much of the 20-year time horizon of the project.

The capital cost of the project is estimated at 2.45 billion dollars (1984 $Cdn.) for the producing and processing facilities. Annual operating costs are estimated at about 100 million dollars (1984 $Cdn.). In addition, the project will require the construction of a 537 kilometre pipeline at a cost of approximately 450 million dollars (1984 $Cdn.). This system will transmit gas through Nova Scotia and New Brunswick to the U.S. border. Here it would connect with a new U.S. pipeline, approximately 500 kilometres in length, that would have to be constructed to interconnect with existing pipelines in Massachusetts for the distribution and sale of gas within the Mid-Atlantic/New England region.

There are sufficient data to perform a simple rule of thumb analysis of required wellhead price for project viability, as outlined in Section 3.2. The rate of decline in natural gas production is assumed to be exponential and is thus approximated by the production-to-reserves ratio as follows:

$$a = \frac{0.1168 \text{ Tcf/year}}{2.36 \text{ Tcf}} = 0.0495$$

If the real discount rate is assumed to be 12 percent to allow for unusual risk in an untried area, we can estimate the ratio of above-ground value to in-ground value as:

$$\frac{P_a}{P_b} = 1 + \frac{i}{a} = 1 + \frac{.12}{.0495} = 3.42$$

The in-ground cost of developing the field is equal to \$2.45 billion/2.36 Tcf or \$1.04 per Mcf (1984 Cdn.). Hence the above-ground cost, or required wellhead sales price, is \$3.55 per Mcf (1984 Cdn.).

Operating costs per unit can be estimated as \$100 million/.1168 Tcf or \$0.86 per Mcf (1984 Cdn.). The value of natural gas liquids production must also be taken into account. If the value of this production is assumed to be \$25.00/bbl (about \$18.00 U.S./bbl) in terms of natural gas production, we must credit about \$1.00 per Mcf against operating costs. Thus, the value of NGL production virtually offsets operating costs and a rough estimate of the required netback price (not including transportation costs) is about \$3.55 per Mcf (1984 Cdn.). Note that this does not include taxes or royalties which could considerably increase the required price.

3.5 Nonconventional Natural Gas Reserves

For the purposes of this study, we consider gas located in very low permeability reservoirs (i.e., tight gas), gas produced from coal seams, and gasified coal to constitute nonconventional reserves. Since tight gas is widely regarded as being the most "near term" alternative of the three categories, our attention will focus on the potential for tight gas reserves and the costs that are likely to be incurred in producing them.

The low permeability of tight gas formations causes gas molecules to flow so slowly that the resultant production rates are so low that these reserves are usually uneconomic to tap with conventional methods. However, the flow of gas can be stimulated with hydraulic fracture treatments in which large volumes of fluid and proppant are injected into a formation at pressures high enough to cause the rock to crack and provide a pathway for increased gas flows. The proppant, a tough sandlike substance such as bauxite, is carried into the fracture by the fracturing fluids. As these fluids break down and leak out of the formation, the proppant remains to prop the fracture open. Without the proppant, underground rock pressures would cause the fracture to close.

Hydraulic fracturing technology has been in use in low permeability oil and gas fields for more than two decades and has been successfully applied in a number of tight gas areas in the United States.[25] Because of the wide variety of characteristics encountered in different types of formations, fracturing is by no means a standardized process. The chosen treatment will vary from formation to formation and depends on many variables including the condition of the formation, the pumping rates and the type of fluid and proppant used. Current research in the U.S. is focussed on controlling the size and direction of the fractures. However, new field development fracture design will likely be guided by a trial and error approach until considerable experience is gained. Certain types of formations will probably never respond to this type of treatment.

Citing an estimate for the gas potential of tight formations without any mention of cost is not very useful. If this potential is only available at prices greater than $10.00 per Mcf, then it is probably not worth considering until market prices begin to approach this threshold level.

Dealing first with the potential for tight gas development within the United States, a considerable amount of work has been carried out to provide estimates of the prices necessary to stimulate further tight gas production. The U.S. recognized as early as the 1960s that low permeability gas-bearing formations might serve as the next major source of natural gas, to complement declining conventional reserves. This realization led to a detailed assessment of the technical and economic potential for tight gas by a multi-company working group of the National Petroleum Council (NPC).[26] Although dated, this study remains the most detailed and perhaps credible study done on tight gas potential.

The Department of Energy (DOE) and the Gas Research Institute (GRI) have since sponsored the construction of a computerized systems model that utilizes the data and methodology developed in the NPC study. The resulting model, known as the "Tight Gas Analysis System" (or TGAS), has the capability of performing sensitivity analyses on major uncertainties, providing a repository for updates of geological, technological, and economic data, and evaluating the potential benefits of tight gas research and development success.[27]

The NPC study and TGAS are a step-by-step analysis of tight gas potential beginning with a thorough geological assessment and ending with projections of tight gas production as a function of time, gas prices, and technology. Twelve geologic basins were appraised in detail. Other basins known to contain tight gas but lacking the necessary data were evaluated by extrapolation through explicit analogy of the appraised basins. Figure 3.12 compares the findings of the NPC and TGAS studies for three levels of prices and two levels of technology in the appraised basins. As illustrated, there is considerable tight gas potential in the U.S. At $2.50 per Mcf (1979 U.S.), the estimated potential is between 100 and 150 Tcf. At $5.00 per Mcf (1979 U.S.), the estimated potential lies between 165 and 230 Tcf. Both higher prices and improved technology dramatically increase the potential contribution of tight gas.

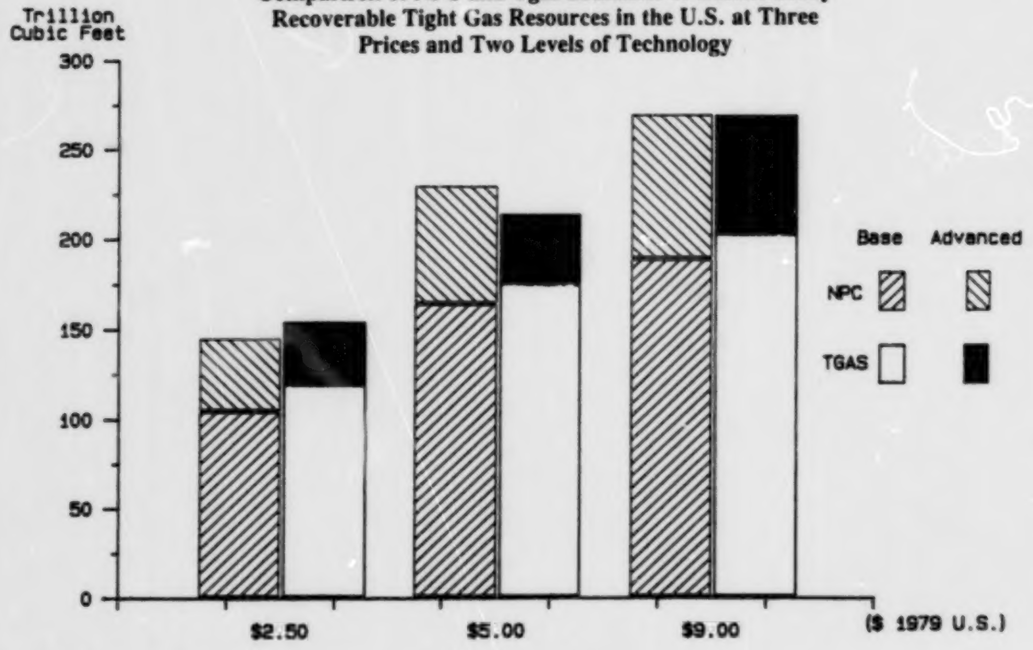
Canadian tight gas potential is concentrated in the deep gas basin of Northeastern Alberta and Northwestern B.C. Estimates of the gas potential of low permeability formations in these areas range from 30 to 400 Tcf.[28] Although no concerted effort has been made to firm up these estimates or to rigorously evaluate the production potential of existing low permeability reservoirs, results to date suggest that viable commercial gas production is possible from these areas given a favourable economic climate. Winters and Associates prepared a study evaluating the possible future supply costs from the deep basin area of Western Canada for the 1979 ERCB hearings on Alberta's ultimate potential of natural gas. The study was submitted as part of AGTL's (now NOVA) submission to the Board.[29]

Winters developed a range of costs likely to be encountered in developing the deep basin. These costs were based on various assumptions regarding permeability, net pay, fracture success, and other reservoir parameters. Fragmentary geological data was used to attempt to establish what percentage of the deep basin potential fell within the various cost categories. The high degree of uncertainty in the analysis regarding key parameters affecting costs, such as permeability and net pay, gave rise to an upper and lower range of likely costs. The major conclusions drawn in the study were:

- about 10 to 30 percent of the deep gas potential could be expected to become available at an in-ground cost of about $1.00 per Mcf (all costs are in constant Canadian 1979 dollars);

Figure 3.12

Comparison of NPC and Tgas Estimates of Economically Recoverable Tight Gas Resources in the U.S. at Three Prices and Two Levels of Technology



SOURCE: Lewin and Associates Inc., Tgas Volume I: Overview, April 1987.

- as much as 50 percent of the gas potential is available at in-ground costs ranging from $1.50 to $2.50 per Mcf; and

- about 30 to 50 percent of the basin potential is expected to be very high cost gas, ranging from $2.50 to $7.00 per Mcf and higher.

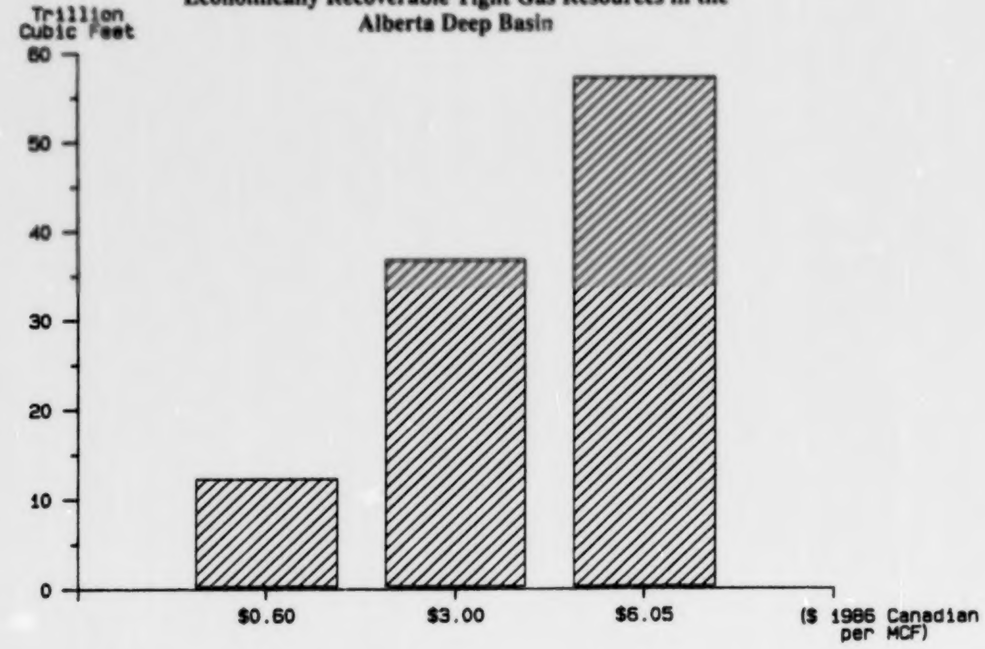
These estimates are supported by the findings of a recent paper on tight gas reserves and deliverability prepared for the Energy Modeling Forum (EMF 9) exercise.[30] Under the wellhead prices assumed in the EMF exercise--$3.14/Mcf (Cdn.) in 1990 and increasing at an average annual rate of 6 percent to $5.75 per Mcf in 2000--deliverability in excess of 1 Tcf per year could potentially be established from the Alberta deep basin by the year 2000. The study assumptions regarding the in-ground cost of tight gas reserves in this region are shown in Figure 3.13. Approximately 37 Tcf are expected to be obtainable at an in-ground cost of less than $3.00 per Mcf (1986 Cdn.). Another 20 Tcf could be available at in-ground costs approaching $6.00 per Mcf.

While the results from these studies are fairly encouraging, they should be tempered with caution given the tremendous uncertainties that exist regarding future technologies, pay zones, and general reservoir characteristics.

Canada's conventional reserves are sufficient to satisfy current demand for over 25 years without any replacement. Therefore, it is expected that government and industry recognition of deep basin potential will develop cautiously. It is also likely that gas from the deep basin will eventually compete with Arctic gas for a share of the U.S. export market. Given the potential of the region and its proximity to existing pipeline systems, an in-depth study of the deep gas basin may be warranted to assess the competitiveness of gas from this region relative to Arctic gas. At stake is the huge investment required to build a polar gas pipeline and the necessity of finding secure markets and sufficient storage to maintain takes of at least 800 Mcf per day of this gas. It may be more economic to develop the deep gas basin at a slightly higher cost to satisfy incremental U.S. demand, and thereby delay the risk and cost of a major pipeline project.

Figure 3.13

Economically Recoverable Tight Gas Resources in the Alberta Deep Basin



SOURCE: Stephen Chesire, Tight Gas Resources, Reserves and Deliverability, Sept 1987.

3.6 An Outlook for Future Natural Gas Supply

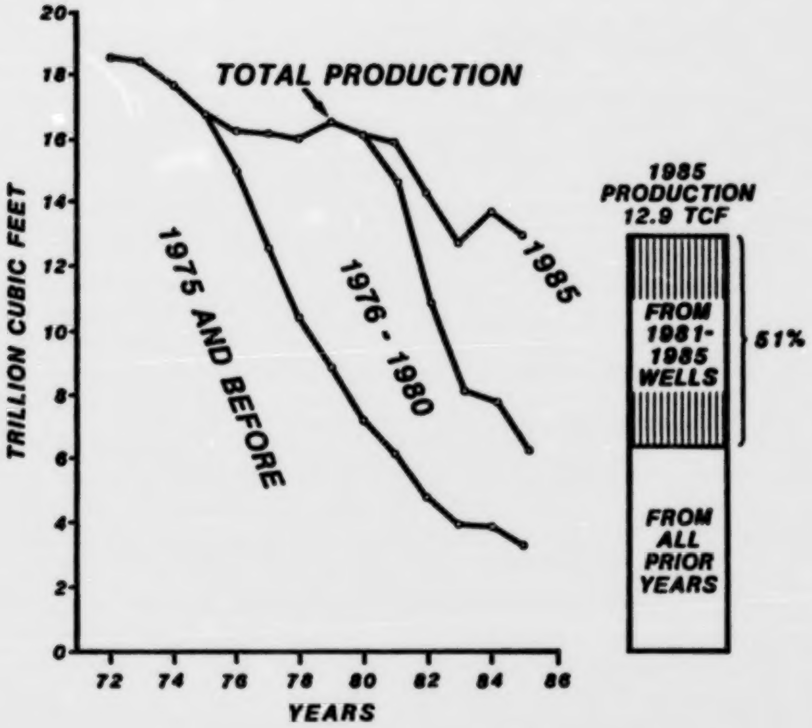
Regulatory policies such as price controls (and, more recently, deregulatory initiatives), government policies regarding royalty collection, tax laws and depletion allowances, and volatile oil prices have introduced serious perturbations into the natural gas industry. The resulting emergence of the gas bubble, extremely low gas prices and the record decline in U.S. gas well completions in 1986 have served to focus attention, especially in the U.S., on short-term issues regarding natural gas supply.

Concern has centered on the inability of low prices (and the concurrent cash flow constraints) to finance sufficient drilling activity to maintain U.S. gas deliverability despite the fact that drilling costs are currently about 58 percent of their 1981 peak.[31] Through the period of dramatic price growth covering the 1970s to the early 1980s, total successful natural gas wells increased four to five fold to an average of 16,800 wells per year. However, this increase was mainly in development drilling as producers sought to increase their productive capacity to generate additional cash flow. As a result, new discoveries have lagged and have failed to replace production for the past nine years although productive capacity has remained stable.

Figure 3.14 summarizes the results of a study conducted by the Texas Oil and Gas Corp. (TXO) on the current state of U.S. natural gas supply. As shown, TXO estimates that about 51 percent of total production from gas wells in 1985 came from wells that were drilled between 1981 and 1985. This implies that wells drilled in the short term will be critically important in maintaining U.S. deliverability. Successful gas completions have declined from 15,388 in 1985 to 7,280 in 1986 and are 35 percent lower through May of 1987.[32] When this trend is combined with the extent to which gas production is dependent on new gas wells, it becomes clear that the gas bubble may not provide enough cushion to prevent regional shortages during peak load periods in the next few years. Moreover, because of poor industry finances, maintenance of existing wells that are producing below capacity or that are shut-in has been deferred. This will also impact on near-term productive capacity.

However, focussing on these short-term issues masks some of the longer-term realities affecting the natural gas industry. Although

Figure 3.14
U.S. Gas Well Production
(by year of completion)



SOURCE: R. C. Bever, Texas Oil & Gas Corporation Gas Market Study, 1986.

future oil prices will continue to be a major determinant of gas prices, in a deregulated market the two prices are essentially decoupled in the sense that gas prices cannot be explicitly linked to oil prices except under contract. Currently, gas prices are generally below oil parity in the spot and direct sales markets because of the excess supply of gas. In the longer term, once this surplus has diminished, the cost of adding additional gas supplies is likely to become a primary determinant of future prices and will determine how competitive gas can be with oil and other alternative fuels.

Over the longer term, the major determinants of natural gas supply cost are the resource base and extraction technology. Conventional theories tell us that, in general, the cheapest and "best" natural gas fields are found and produced first. Larger fields have a higher probability of being found than smaller fields and exploration in the early stages is likely to be concentrated in the most favourable locations in terms of geology and proximity to markets. As the resource base becomes more mature, smaller, deeper, and more remote plays are explored. Offsetting this upward pressure on supply costs is the increased knowledge of explorationists in terms of both geology and seismic technology, and producers in terms of improved technologies to increase the recovery of gas in place. How these opposing forces--advancing technical and geological knowledge versus a declining resource base--interact in the future will determine the cost of obtaining additional natural gas supplies.

The most readily observed indicators of a declining resource base are:

- a decline in average field size over time;
- an increase in the average depth of fields over time; and
- the shifting of exploration resources to less favourable locations.

Other factors, such as a movement to produce less favourable zones within an existing field, are much more difficult to observe on a national level.

Table 3.10 presents natural gas field discoveries and mean field size by decade of discovery and region for the United States. From the 1920s to the 1950s, the increase in discoveries in each decade outpaced the decrease in mean field size so that more reserves were found in each successive decade. Discoveries, as measured by recoverable resources in newly discovered fields, peaked in the 1950s, after which the number of new fields failed to offset the decrease in field size, resulting in fewer reserves being discovered. Even though almost one-half of all known fields were discovered after 1970, these fields contain less than 16 percent of the known ultimate recoverable gas. The trend is obvious; average field sizes in all regions of the United States have been declining over time.

TABLE 3.10

U.S. ONSHORE LOWER-48 MEAN FIELD SIZE BY DECADE OF DISCOVERY

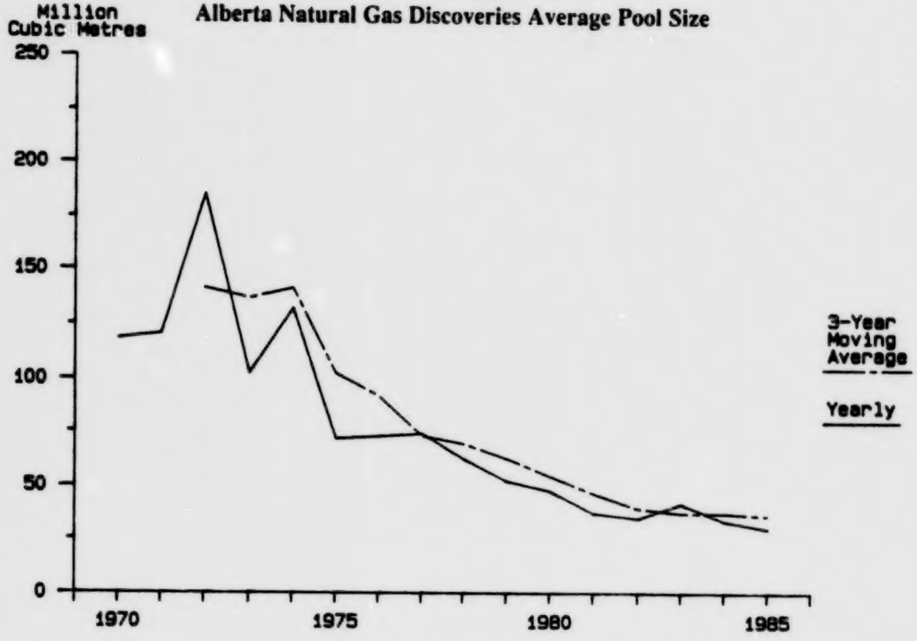
Decade of Discovery	Mean Field Size (trillion Btu)
1920	404
1930	332
1940	124
1950	50
1960	27
1970	12
1980-1982	5

SOURCE: Energy Information Administration Office of Oil and Gas: Crude Oil and Natural Gas Resource Evaluation System (Congress).

NOTE: Mean Field Size as measured by Ultimate Recoverable Resource.

This same trend is apparent in Alberta as evidenced by Figure 3.15. Average pool size has declined from about 5000 Mcf in 1975 to close to 1000 Mcf in 1985. The impact of declining pool size on costs is felt mainly through a loss in economies of scale. Gathering lines and surface equipment costs are likely to increase on a per-unit basis for smaller pools and drilling costs can be reduced if numerous wells are drilled in the same area. In very small pools the volume of initial marketable reserves might not be sufficient to fully utilize the capacity of a single well, so that per-unit costs are greater than would be observed in a large field. What impact the observed trends to smaller pools in both countries will have on future supply costs is difficult to assess. But as the larger, older discoveries are depleted

Figure 3.15
Alberta Natural Gas Discoveries Average Pool Size



SOURCE: Alberta Energy Resources Conservation Board.

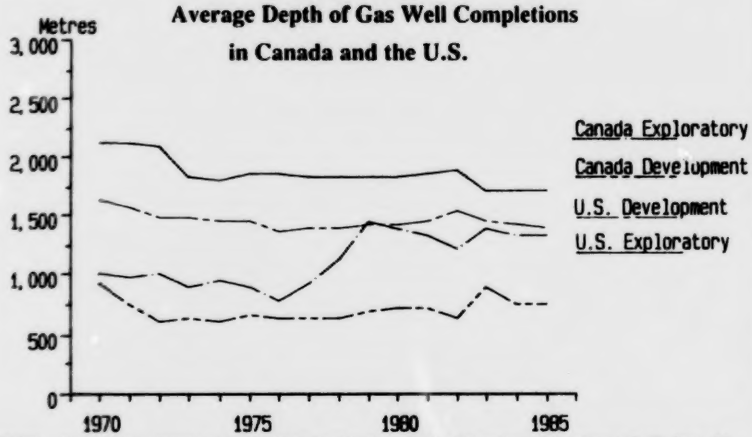
and smaller ones are brought into production, an increase in average supply costs can be expected to occur.

Drilling depth is another important factor affecting costs because drilling costs increase exponentially as a function of depth. Figure 3.16 illustrates the trends in depths for development and exploratory drilling in Canada and the U.S. for the period 1970-1985. Neither exploratory nor development drilling depths have increased significantly over time in the U.S. The average depth of exploratory wells in Canada increased from an average of about 1000 metres between 1970 and 1976 to 1500 metres after 1977. As the deep basin areas in the two countries are thought to contain considerable gas potential, it is likely that average depths for both exploratory and development wells will begin to increase over time.

In our analysis of reserves in the two countries, we addressed the notion of a finding rate (see Figures 3.4 and 3.8). In both countries, additions to reserves peaked and declined to fairly stable levels over the last few years. This decline is caused mainly by smaller discovered pools over time due to the depletion of each region's ultimate potential. However, drilling success rates have been maintained, and have even increased on average over time as shown in Figure 3.17. Note that the level of reserves per well necessary to make a well economic has also decreased as prices increased. Higher success rates do signal some technological gains in the exploration process and could offset, to some extent, upwardlpressure on costs due to declining finding rates. Moreover, improvements in the recovery of gas in place could stabilize finding rates in the future and lessen upward pressure on gas costs.

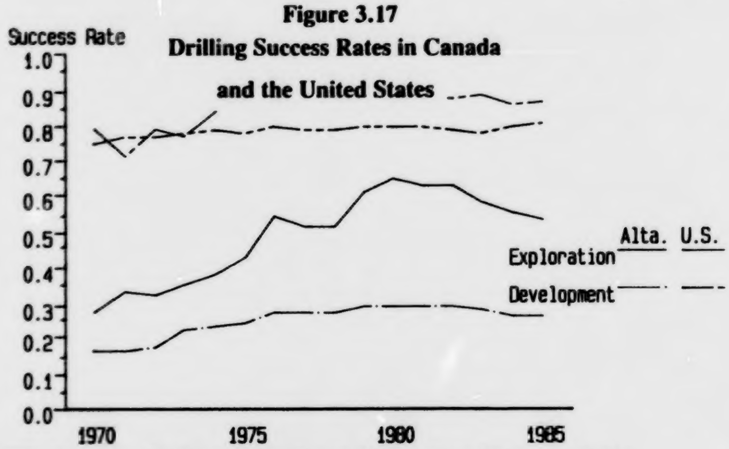
While there is sound reason to believe that future supply costs will increase over time due to the above factors, the ultimate potential for gas in both Canada and the United States suggests that there are large volumes of gas still to be found. The Geological Survey of Canada estimates, with an average expectation, that 2504 billion cubic metres (88.4 Tcf) of gas remain to be discovered in the Western Sedimentary Basin. However, their speculative estimate of 4930 billion metres (174 Tcf) is nearly double this quantity. The Potential Gas Committee (PGC) believes that about 20 934 billion cubic metres (739 Tcf) remain to be discovered in the U.S. These estimates of ultimate potential are subject to great uncertainty and are of limited use if no costs are attached to them. For instance, given that Canada's ultimate potential is close to 100 Tcf, if only 30 Tcf of this potential is

Figure 3.16
Average Depth of Gas Well Completions in Canada and the U.S.



SOURCE: U.S. Data; American Petroleum Institute, Basic Petroleum Data Book V6, #3 Sept 86.
Canadian Data; Canadian Petroleum Association, Statistical Handbook.

Figure 3.17
Drilling Success Rates in Canada and the United States



SOURCE: U.S. Data; The American Petroleum Institute, Basic Petroleum Data Book, Volume VI, Number 3, Sept. 1986.
Canadian Data: Canadian Petroleum Association, Statistical Handbook.

economic at prices below $10.00 per Mcf, it may not be wise to even consider the latter 70 Tcf as potential gas reserves.

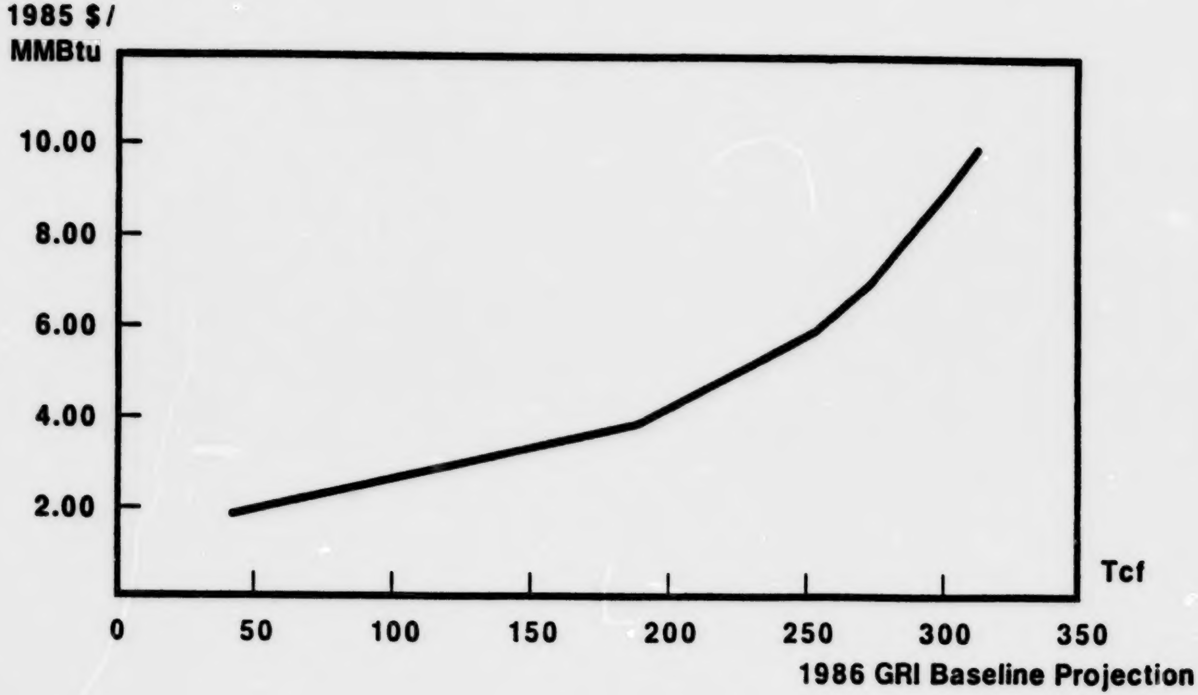
The GRI has attempted to address this question (and many others) through the construction of their Hydrocarbon Supply Model. The model provides a rigourous and consistent framework for analyzing the resource cost of finding, developing, and producing natural gas and crude oil in the Lower-48 states. The major data input to the model is information on individual oil and gas fields found in the United States to the year 1980. Find-Rate equations are estimated on a regional basis and linked to a cost algorithm to provide the capability of analyzing full-cycle costs on a regional basis.[33]

Figure 3.18 presents the resource cost curve generated by the Hydrocarbon Supply Model for the undiscovered Lower-48 gas resource, based on the 1986 GRI baseline price projection. The curve shows that about 200 Tcf of the undiscovered resource is economic at prices below $4.00 per MMBtu (1985 $U.S.). About 90 percent of the resource is economic at prices below $7.50 per MMBtu. The increase in resource costs for onshore fields is driven primarily by increased costs to find new fields. Finding costs account for 60 to 70 percent of the marginal costs for the lowest cost increment in most onshore regions. In the highest cost increments, between 80 and 90 percent of the marginal cost is due to finding costs. In offshore regions, higher development costs offset to some extent the dominance of finding costs.

Unfortunately, a similar model of the Canadian natural resource base does not exist. The Geological Survey of Canada relies entirely on geological and statistical techniques. They make some reference to drilling costs in different regions but no costs are attached to any of the estimates of gas potential. It is reasonable to suppose that, based on U.S. evidence and the finding cost estimates developed by CERI for Canada, finding costs will begin to dominate supply costs in the Western Sedimentary Basin as depletion of the region's reserves progresses.

In summary, the Canadian and U.S. gas resource bases are likely to be of greater magnitude, and less expensive to access than is commonly perceived. Estimates of the ultimate potential in each country are constantly being revised upwards. For example, the NEB's mid-1970s estimate of 115 Tcf for Canadian ultimate potential was surpassed by total initial established reserves in the early 1980s. The Geological Survey of Canada (GSC) has revised its estimates of the

Figure 3.18
Undiscovered Lower-48 Resource Cost Curve
(as of January 1, 1981)



SOURCE: Gas Research Institute, 1986.

average expectation of gas potential in the Western Sedimentary Basin from 107 Tcf in 1975 to 206 Tcf in 1983. New GSC estimates, likely to contain further upward revisions, are expected to be published in 1988. Given this resiliency, it is not unreasonable to expect that natural gas could provide a large portion of total North American energy requirements for the next half century. The determining factor, however, will be whether or not gas can remain competitive with alternative fuels in the longer term.

Footnotes

[1] These are the definitions used by the Canadian Petroleum Association. Very similar definitions are employed in the U.S.

[2] American Petroleum Institute, Basic Petroleum Data Book, vol. VI, no. 1 (Washington D. C.: American Petroleum Institute, January 1987), Section III, Table 1.

[3] This simple analysis is based on the approach of Adelman, Haughthon, Kaufman, and Zimmerman, Energy Resources in an Uncertain Future (Ballinger, Cambridge, Massachusetts, 1983), Appendix B. A more complex, but similar analysis that accounts for different types of taxes is derived in United States, Department of Energy, Energy Information Administration, An Economic Analysis of Natural Gas Resources and Supply (Washington: Energy Information Administration October 1986), pp. 163-165.

[4] A fairly detailed breakdown of drilling costs in various regions of the Western Canadian Sedimentary Basin is provided in Petroleum Services Association of Canada (PSAC), Well Cost Study July 1986 (Calgary: PSAC, July 1986).

[5] The source for this data is the Canadian Petroleum Association, CPA Statistical Handbook, 1985 Edition (Calgary: CPA, 1985).

[6] This volatility is perhaps even more evident if one examines trends in Saskatchewan's natural gas reserves in 1985 and 1986. Saskatchewan's established reserves more than doubled in 1986 from 25.8 million cubic metres to 61.3 million cubic metres due to gross reserves additions totalling 37.2 million cubic metres (compared to the -8.7 million cubic metres estimated for Alberta gross reserves additions in that year).

[7] United States, Department of Energy, Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquid Reserves 1985 Annual Report and An Economic Analysis of Natural Gas Resources and Supply (Washington: Energy Information Administration, both published October 1986).

[8] U.S., Department of Energy, Energy Information Administration, An Economic Analysis of National Gas Resources and Supply (Washington: EIA October 1986), pp. 38-40.

[9] A discovery will generally appreciate or grow in size over time as more knowledge is obtained through production experience and additional development drilling. The Energy Resources Conservation Board has estimated the long-term appreciation factor for Alberta to be slightly greater than 5. However, in recent years a greater percentage of reserves additions have been located in smaller fields and it is generally accepted that smaller fields appreciate less. The Canadian Energy Research Institute, argues for an appreciation rate of 3.4 for

the year of discovery, declining to 1.0 five years after discovery (see Janice Pasay, Oil and Gas Finding Costs in Alberta: 1978-1985, Research Report 87-1 (Calgary: CERI, January 1987), pp. 6-14.

[10] See Janice Pasay, op. cit.

[11] See P. Eglington and M. Uffelman, Observed Costs of Oil and Gas Reserves in Alberta, 1957-1979, Economic Council of Canada, Discussion Paper No. 235 (Ottawa: Economic Council of Canada, May 1984), pp. 19-22.

[12] Canadian Petroleum Association, Historical Analysis of Industry Operating Costs (Calgary: CPA, June 20, 1983).

[13] See Adelman and Lynch, "Supply Aspects of North American Trade in Natural Gas," in Canadian-U.S. Natural Gas Trade by the International Gas Trade Project (Massachusetts Institute of Technology, October 1985), pp. 15-18.

[14] Canadian Petroleum Association, CPA Statistical Handbook, 1985 Edition (Calgary: CPA 1985).

[15] This measurement of the capital cost component of gas plant operation reflects the volatile nature of annual reserves additions and varies correspondingly. On average, when combined with gas plant operating costs, it falls in the range of customer processing fees charged by the various plant operators in the provinces. These fees range anywhere from $.20 per Mcf to over $1.00 per Mcf depending on the age of the plant, the region, and if there is sulphur in the gas.

[16] See Energy Pricing News, Petrochemical Report, vol. 7, no. 8, August 11, 1987.

[17] Processing fees for sour gas average about $1.00 per Mcf, a little more than twice the average for sweet gas. Moreover, sour gas is generally found in regions with high drilling costs such as the Foothills region. Since the gas is usually rich in NGLs, however, and the value of the sulphur can be as great as $1.60 per Mcf of marketed gas production (at $115 per tonne), the higher revenue can more than offset increased drilling and processing costs.

[18] See, Canada, Geological Survey of Canada, Oil and Natural Gas Resources of Canada 1983, Paper 83-31 (Ottawa: Minister of Supply and Services, 1984), p. 28.

[19] Ibid., p. 28.

[20] CPA Statistical Handbook, various editions.

[21] See Geological Survey of Canada, op. cit., p. 24.

[22] See Polar Gas, Polar Gas Project Presentation to the House of Commons Standing Committee on Energy, Mines and Resources on February 10, 1987 (Toronto: Polar Gas Project, April 1987).

[23] See Geological Survey of Canada, op. cit., p. 33.

[24] See Venture Gas Project, Application to the National Energy Board for an Export License, vol. 1, Chapter 2.

[25] The GRI estimates that more than 1 Tcf of Lower-48 gas production comes from areas that could be considered nonconventional.

[26] National Petroleum Council, Unconventional Gas Resources, Tight Gas Reservoirs, vol. V, (June 1980).

[27] Lewin and Associates Inc., TGAS: The Tight Gas Analysis System Volume I Overview, Final report prepared for the Gas Research Institute (April 1984).

[28] Alberta Energy Resources Conservation Board, Ultimate Potential for Gas in Alberta, Report 79-6 (Calgary: ERCB, November 1979).

[29] C. R. Winters and Associates, Study of Unconventional Gas Reserves in the Alberta Deep Basin Area, Submission to the Alberta Energy Resources Conservation Board, Ultimate Potential for Gas in Alberta (Calgary: 1979).

[30] Stephen Cheshire, Tight Gas Resources-Reserves and Deliverability, Prepared for the EMF 9 Exercise (Calgary: Canadian Hunter Exploration, September 1987).

[31] United States, Department of Energy, Energy Information Administration, Indexes and Estimates of Domestic Well Drilling Costs 1984 and 1985 (Washington: EIA, November 1985) p. 120.

[32] See American Gas Association, Executive Gas Statistics, (September 1987).

[33] For an indepth discussion of the various components comprising the Hydrocarbon Supply Model see Energy and Environmental Analysis, Inc., Guide to the Hydrocarbon Supply Model, prepared for the Gas Research Institute (Washington, D.C.: GRI, June 1985).

Chapter 4

NATURAL GAS DEMAND

4.1 Introduction

Natural gas as a fuel has many desirable qualities. In its marketable form, natural gas usually consists of 85 to 90 percent methane and is free from toxins and corrosion agents. It is remarkably clean burning and efficient in combustion. In the residential and commercial sectors, natural gas has the property of being "instantly deliverable." This feature, in conjunction with the aforementioned properties, makes it an ideal fuel for purposes of space heating and cooling and meeting the peak load demand associated with such services. Its low toxin content helps industrial users and electric utilities meet stringent environmental standards at little or no added cost. For these reasons and because it is very competitively priced relative to other fuels, natural gas has gained a dominant share in total energy demand, second only to oil in both Canada and the United States.

This chapter is intended to provide an overview of the principal determinants of natural gas demand in the various end-use sectors, a review of historical consumption patterns, and our outlook for future natural gas demand. The first section discusses the distribution sector, identifying some key issues and characteristics, and the major players in the sector. Following this, we present the modelling framework used to forecast natural gas demand. The final three sections examine historical and future natural gas demand in each of the three major end-use sectors--the residential, commercial, and industrial sectors--on a regional basis. This approach acknowledges that natural gas consumption varies considerably by sector and by region because of differences in energy using technologies, climate, etc., and is consistent with the regional and sectoral disaggregation employed in the Gas Research Institute's (GRI) North American Regional Natural Gas Model.

4.2 The Distribution Sector

Agents on the demand side of the natural gas industry include local distribution companies (LDCs) and individual end-users of natural gas. The distribution of gas to end-users is the final link in the transportation chain from wellhead to burner-tip. Because of the number and geographical diversity of end-users, the capital investment for the miles of pipelines and compression facilities required to deliver gas to LDC customers is enormous. Moreover, each individual user's consumption must be monitored for billing purposes and the entire system and storage facilities must be designed to meet peak load requirements which vary by time of day and season.

In order to achieve the economies of scale necessary to provide these services at a competitive price, it has been necessary to award LDCs a natural monopoly within a certain geographical region or franchise area. Within this area, the LDC retains the sole right to provide natural gas service to interested parties. The natural monopoly attributes of LDCs--considerable barriers to entry and economies of scale--require that their cost and revenues be regulated to ensure a fair return on investment and that their pricing practices are nondiscriminatory. In North America, this regulation takes place at the state and provincial level according to traditional cost-of- service methods.

The regulator is also responsible for allocating these costs among the different classes of customers, ideally on the basis of the cost of providing such service although low gas prices in the past have allowed regulators to tilt rates in favour of the core market. Costs between different classes of customers vary considerably and depend on, among other factors, the cost of monitoring actual consumption. For large users this cost is considerably less than for small users, on a per-unit basis. The timing and seasonality of demand also impacts on costs: large users who utilize gas for boilers, process heat or feedstock purposes basically have a constant take of gas throughout the day and year and do not require the peaking and storage facilities that smaller users do, who use gas primarily for space heating or cooling and whose demand varies considerably depending on the time of day and climate.

Before the advent of deregulation, LDCs generally purchased all their gas supplies in bundled packages from pipeline companies. These packages included the gas, whose cost was the weighted average of the pipeline's suppliers, and transportation service. Contracts between an LDC and a pipeline were typically long term (10 to 20 years) and involved some sort of obligation on the part of the LDC to pay a portion of the pipeline's fixed costs in the form of a demand charge and/or minimum bill requirement. The final cost of gas, or burner-tip price, to the various classes of customers included the LDC's purchased gas cost and a distribution margin which reflected the cost to the LDC of providing service plus a rate of return on the capital investment. Given that the price an LDC paid for gas was regulated, regulatory bodies simply allocated the cost of service among the different classes of customers according to traditional arrangements and approved system expansion when it was applied for and warranted.

It can be argued that wellhead decontrol and changes in pipeline regulation will be thwarted at the city gate unless changes extend all the way to LDCs. Although it is not readily apparent in today's low gas price environment, given the inevitability of increasing gas costs (and downward instability in world oil prices), competition from alternate fuels will intensify over time. The pricing rules employed by regulatory commissions and the services offered by LDCs must be sufficiently flexible to meet this increasing competition. Burner-tip prices must be set so that an LDC can both recover sufficient revenue to obtain an adequate return on investment and meet price competition in the industrial sector.

A number of methods for providing this flexibility have been suggested, some of which are in the process of being implemented. One possible pricing strategy for dealing with the dual-pronged problem of meeting price competition and recovering sufficient revenue is illustrated in the following example. A very realistic scenario in the near to medium term is that gas prices may exceed fuel oil prices in the industrial sector for a sustained period of time. In this situation, LDCs face the risk of losing substantial load to fuel oil if they cannot meet or better the prevailing fuel oil price. Failure to do so would cause gas prices to their remaining customers to increase because revenues must be recovered from a smaller customer base. They could, however, avoid this situation by setting prices in the industrial sector according to the price of the principal competing fuels (fuel oil in this case), and recovering the remaining required revenue from other customers who would have seen a price increase in either situation.[1] The tradeoff, of course, is in which case the price increase is larger.

A move to equalize rates of return an LDC recovers from different classes of customers would also improve the competitiveness of gas in the industrial sector if, as many observers contend, regulators have tilted the rate structure in favour of residential consumers. As a complement to the above, or as an alternative, LDCs could lower gas purchase costs if they were to arrange a portfolio of suppliers. Generally, gas sold on a short-term basis is cheaper than gas sold under a long-term basis. By arranging an array of different length contracts that reflect the distribution of customers between core and non-core, and their corresponding need for secure supplies, an LDC could stream the cheaper shorter-term gas to industrial users and the longer-term, secure supplies to the core market. However, this would generally require that LDCs reduce takes of pipelines system gas and contract directly with producers or brokers.

It is likely that some form of regulation or monitoring process will be required regarding an LDC's use of brokers and the direct purchase of gas on spot markets, to ensure that sufficiently secure supplies are being obtained. Unlike a pipeline company, if a broker fails to deliver gas, his capital structure is likely to be such that the LDCs will be unable to collect the requisite damages. A supply portfolio, however, should provide insurance that adequate supplies remain to meet the system's requirements.

Finally, an LDC should offer the same type of transportation service currently being offered by pipelines so that large end-users can contract directly at the wellhead according to their particular needs, and have that gas transported at reasonable cost to their facilities. In order to provide this transportation service, regulatory commissions must restructure and unbundle rates so that they better reflect the costs of providing the individual services traditionally rendered by the LDCs on a fully bundled basis. Ideally, LDCs, like pipelines, should be indifferent between transporting and selling the gas.

Deregulation has also raised the possibility of "bypass" whereby a customer, usually an energy intensive industrial user who feels that he can provide the same transportation service the LDC is providing at a lower cost, can bypass the LDC and construct a private pipeline connecting the industrial site directly with the supplying pipeline. To date, the threat of bypass has been mainly used as a negotiating tool by large natural gas users seeking lower transportation costs.

The above features have been introduced, to some extent, into the distribution sector. However, given that LDCs and their regulators have operated in a controlled market for many years, the managerial and regulatory skills necessary to deal with the complexities of a deregulated market will take time to develop. Nevertheless, when gas-on-gas competition lessens and supply and demand come into balance in the future, increased flexibility in the prices and services offered by LDCs will be required to retain load and meet future competitive challenges.

4.2.1 The Canadian Distribution Sector

Jurisdiction over energy development, transportation, and use in Canada is divided between the federal and provincial levels of government. The Constitution Act of 1867 sets out the powers of the provincial and federal governments such that the provinces retain the right to develop resources within their own borders while the federal government regulates all interprovincial and export trade and commerce.[2] Thus, the National Energy Board (NEB) is empowered to regulate the transmission of natural gas across provincial and national borders while the provinces maintain regulatory authority over the production and marketing of gas within provincial borders. Within each province, a regulatory body such as the Alberta and Manitoba Public Utilities Boards (PUB) or the Ontario Energy Board (OEB), has the authority to determine final natural gas prices.

The Canadian distribution sector is dominated by seven major gas distribution companies: Canadian Utilities Ltd., Saskatchewan Power Corporation, ICG Utilities, B.C. Hydro, Consumer's Gas Company Ltd., Union Gas Limited, and Gaz Metropolitan.

Canadian Utilities Limited divides the Alberta market into north and south, managing the north through North Western Utilities Ltd. and the south through Canadian Western Natural Gas Company. Not included is the City of Medicine Hat which manages its own gas distribution system. Saskatchewan Power Corporation services all of the province of Saskatchewan with the exception of the City of Lloydminster which, as in the case of Medicine Hat, provides for its own distribution needs through a local distributor. B.C. Hydro, a Crown corporation, is the largest distributor in the province, servicing Greater Vancouver and the Fraser Valley.

ICG Utilities provides distribution services to several provinces. As well as servicing customers in British Columbia, Alberta, Ontario, and Manitoba, ICG Utilities is a major shareholder in Gaz Inter cite Quebec, the distributor which services most of Quebec. ICG

Utilities is also the franchise distributor of natural gas for New Brunswick.

Union Gas Limited and Consumer's Gas Company dominate Ontario's gas distribution sector. Consumers' Gas services the Metro Toronto and central regions of Ontario. Union Gas serves the most southern region of Ontario including London, Windsor and the Sarnia industrial area. Both utilities purchase nearly all their gas supplies from TCPL through Western Gas Marketing Ltd (WGML).

As noted in Chapter 2, Canadian LDCs have come a long way in implementing some of the precepts of a deregulated market. Nearly every LDC offers some sort of transportation service. The Ontario Energy Board (OEB) has proceeded the farthest in ordering that rates of return from different classes of customers be equalized and that services should be unbundled to allow customers to choose those services that meet their specific needs. However, the existence of long-term contracts with WGML and the NEB's self displacement provision have effectively prevented Canadian LDCs from arranging their own supply portfolios. As contracts with WGML expire in the early and mid-1990s, this option will become increasingly available. In the meantime, WGML's reluctance to extend discounts to the core market comparable to those they are offering the industrial market, and the inability of LDCs to obtain less expensive direct sales gas for the core market because of the self displacement proviso, have caused considerable controversy.[3]

The cost of transporting gas from the wellhead to the burner-tip is a major variable in determining natural gas demand by sector and region in the Canadian component of the regional gas model. An important element of this cost is the distribution mark-up or margin from the city gate (where the utility receives the gas) to the burner-tip. This margin varies considerably between different classes of consumers.

Table 4.1 presents average distribution costs on both a sectoral and regional basis as required in the regional gas model. It should be noted that LDCs do not distinguish between sectors to allocate costs but do so on a volumetric basis; the more gas taken the lower will be the per-unit price paid for that gas. As shown in the table, distribution costs to the industrial sector are about 20 percent of those to the residential sector, reflecting the much larger volume requirements per customer. Given that the cost of transportation from Alberta to

TABLE 4.1
NATURAL GAS DISTRIBUTION COSTS IN CANADA
($ per gigajoule)

	Western Canada[b]	Ontario[c]	Quebec
Residental	2.41	2.78	3.18
Commercial	1.35	1.24	2.12
Industrial	0.45	0.35	0.51

SOURCE: Canadian Energy Research Institute.

[a] Average distribution margins calculated from various 1985 annual reports and the EMR Statistical Handbook--Representitive Natural Gas Prices. Effective date: September 1987.

[b] Weighted average of distribution margins within B.C., Alberta, Saskatchewan and Manitoba.

[c] Ontario distributors have generally unbundled their rate structure so that large industrial users can obtain transportation service for as low as $0.16 per gigajoule on either Consumers' or Union's system.

the Toronto city gate is about $1.23 per gigajoule, distribution costs make up a major portion of total transportation costs, especially in the residential and commercial sectors.

4.2.2 The U.S. Distribution Sector

In the U.S., LDCs are regulated in much the same manner as in Canada. That is, LDCs are regulated at the state level by Public Utility Commissions (PUCs) who regulate price, term, volume, and other factors in arrangements between LDCs and end-users. PUCs also establish a ranking of priority end-users which is referred to when the question of curtailment arises. The national system of supply priorities gives priority to residential and commercial users who have no alternative energy supplies. To ensure that this standard is referred to in rate making, the Public Utility Regulatory Policies Act (PURPA) was passed in 1978. This Act outlined three major objectives for rate design: the efficient use of utility facilities and resources; equitable rates for utility customers; and the conservation of energy.[4] Rate making remained a state (and therefore a PUC) perogative, but was expected to conform to national standards.

There are over 1400 LDCs in the U.S., with considerable variance in terms of size, assets, and service area. Some LDCs serve only small communities while others, like the Southern California Gas Co., (SoCal) Pacific Gas and Electric, and Brooklyn Union, span thousands of square miles and serve millions of people. The 100 largest LDCs account for 75 percent of total sales and the 10 largest for 25 percent.[5] Since LDCs are regulated at the state level, state- specific political, social and economic objectives often dictate the actions of their respective PUCs. The heterogeneity across states has resulted in LDCs facing different regulations from state to state and is likely to result in a rather inconsistent implementation of the essential precepts required for deregulation in the burner-tip market.

One result of U.S. deregulatory initiatives has been to free LDCs from traditional long-term contracts signed with pipeline companies during the late 1970s and early 1980s when pipelines were essentially the only sources of supply.[6] This has allowed LDCs to diversify their supply portfolio among a number of different sources and follow a least cost purchasing program. It has also opened up a huge potential market for Canadian exporters in terms of the number of buyers capable of purchasing Canadian gas. The many barriers that still face Canadian exporters in their attempt to efficiently access this market are formidable and center on the availability of transportation service on U.S. pipelines (this discussion is relegated to Chapter 5). Appendix F provides a discussion of the essential characteristics of the major U.S. LDCs in those regions having access to Canadian gas. A breakdown of the demand and supply profiles of these LDCs is also provided.

Transportation access, not only on pipelines but also on LDCs, will be critical if the U.S. market potential is to be fully realized by Canadian producers and brokers. Transportation access on LDCs will allow Canadian producers and brokers to more effectively capture specific end-use markets such as large industrial users and electric utilities. To date a number of PUCs have implemented transportation rates for their LDCs.[7] However, in many instances these rates have not been unbundled and simply consist of gross margin rates (the distribution margins described above) which do not reflect the actual cost of the service.[8] Considerable pressure is being exerted to align these rates more closely to direct costs, including the threat of bypass and possible load loss to competing fuels.[9]

4.3 The Modelling Framework for Forecasting Natural Gas Demand

The demand for energy is intrinsically tied to the characteristics of the capital stock it is fuelling and the end-use services that the capital stock is providing. For instance, the demand for a service is primarily a function of the price of that service. From this demand, a demand for equipment is derived which is a function of the equipment cost and associated operating costs. Finally, the demand for different fuels is determined by their relative prices, the final demand for services and the choice of fuel-using equipment. Fuel choices are also limited by available technology, and inherent fuel characteristics such as mobility, burning properties, chemical properties, and utilization efficiency.

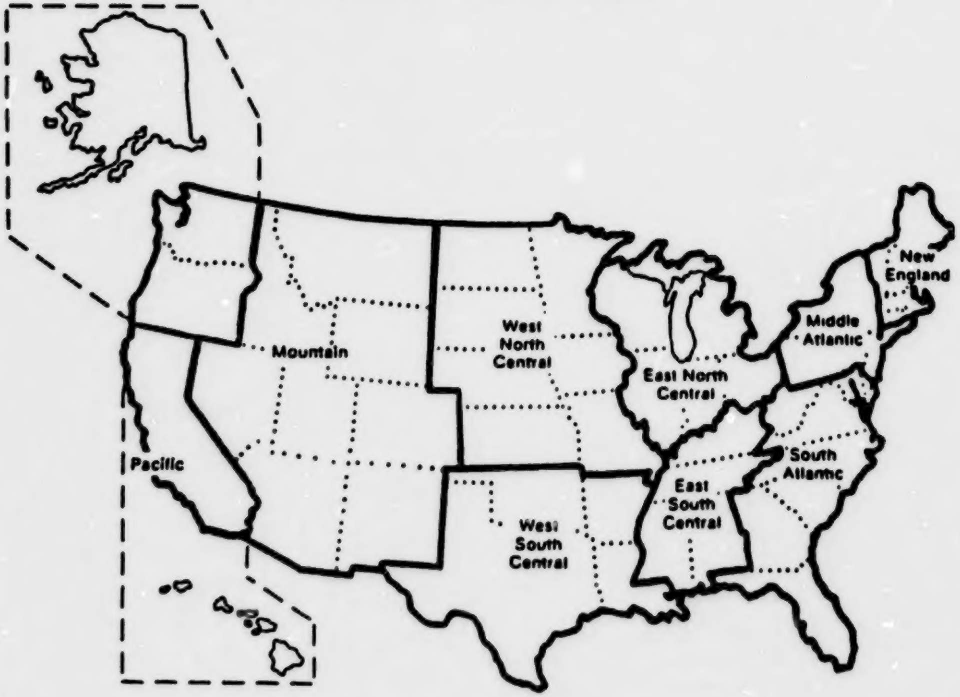
Once the choice of fuel-using equipment has been made, the demand for energy becomes time oriented. Consumers are limited in their ability to immediately respond to price changes. In the short term their response is limited to more or less use of their existing stock of energy consuming equipment. Over a longer period of time, a greater response to price changes can be achieved by altering the stock of energy-using equipment through new purchases or retrofitting existing stocks. Conservation measures and more fuel efficient technologies will also impact on energy demand over time.

The demand for natural gas varies considerably by the end-use consuming sector because of differences in final service demands, energy using technologies and interfuel substitution possibilities, and by geographical region because of differences in climate, population growth and income growth. The modelling methodologies used to form our forecast of natural gas demand attempt to incorporate all the above factors in their framework. The Canadian Regional Energy Demand Model (CREED) model, an end-use multi-fuel demand model developed by CERI that is capable of forecasting natural gas demand on a provincial and sectoral basis, was used to prepare forecasts of Canadian natural gas demand.[10] The analysis of future U.S. natural gas consumption is based on the 1986 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010.[11]

The regional disaggregation employed on the demand side of the GRI North American Regional Natural Gas Model is as follows. The Canadian component is composed of three regions--Western Canada, Ontario, and Eastern Canada--which are further broken down into three end-use sectors: the residential, commercial, and industrial sectors. Gas demand was forecast on a provincial basis for each of the three sectors and then aggregated on a sectoral basis to achieve consistency with the model's regional structure. The regional disaggregation of the U.S. market corresponds to the census regions in the U.S. The historical precedent of using census regions has generated copious amounts of accepted data. In addition to this feature, climatic distinctions are also reflected along census boundaries, making demand/consumption patterns easier to grasp intuitively. Where climatic and transportation differences are minimal, the census regions in question are aggregated for simplicity. The seven resulting demand regions (depicted in Figure 4.1) are:

(1) Pacific Coast
(2) West North Central/Mountain
(3) West South Central
(4) East North Central
(5) East South Central
(6) South Atlantic
(7) Middle Atlantic/New England

Figure 4.1
United States Demand Regions


New England
Middle Atlantic
South Atlantic
East North Central
East South Central
West North Central
West South Central
Mountain
Pacific

SOURCE: DFI, The GRI North American Regional Gas Supply-Demand Model, Figure 3-25.

The U.S. side of the market is further disaggregated into residential, commercial, industrial and electric utility sectors, corresponding to the submodels of the GRI Baseline Projection.[12]

Table 4.2 presents the key economic assumptions underlying the demand forecast. Annual real GNP growth in both countries is assumed to average close to 3.0 percent per year. Inflation is expected to increase over time from an annual rate of 4.9 percent in 1990 to 6.0 percent in 2010 primarily due to increasing energy costs. Crude oil prices are forecast to increase from $20.40 ($1985 U.S.) per barrel in 1990 to $26.75 per barrel in 2000, an average annual increase of about 2.5 percent. After 2000, crude prices accelerate more rapidly as the OPEC share of world production increases. Prices increase at an annual average rate of 4.5 percent to $40.00 ($1985 U.S.) per barrel in 2010.

4.4 The Residential Sector

In the residential sector, natural gas is used primarily for space and water heating and, to a smaller extent, to fuel various household appliances such as clothes dryers and stoves. The primary determinants of natural gas demand in this sector are:

- the burner-tip price of gas which varies considerably on a regional basis depending on the proximity of the consuming region to supply regions;
- the price of near substitutes--mainly distillate fuel oil and electricity--which also vary on a regional basis;
- the limits of the existing pipeline infrastructure, which determines availablity and capacity;
- household income, which determines the size of housing and the penetration of energy using appliances;
- demographics, which determine population growth (or shrinkage) in a region and hence the potential for growth in housing and apartment starts and for increased appliance demand in that region;
- the average daily temperature of a region, since natural gas is used primarily for space heating/cooling;
- the existing stock of housing and energy using appliances and their inherent technical characteristics such as insulation and the energy efficiency of household appliances; and

TABLE 4.2

KEY ECONOMIC ASSUMPTIONS UNDERLYING THE NATURAL GAS DEMAND FORECAST

	Real GNP Growth		U.S. Consumer Price Index	U.S. Prime Interest Rate	Refiner Aquisition Cost of Crude Oil (1985 $U.S. per barrel)
	Canada	U.S.			
1990	2.8	3.6	4.9	8.7	20.40
1995	2.8	2.8	5.2	-	23.00
2000	2.8	3.1	5.0	9.0	26.75
2005	2.8	2.9	5.5	-	32.50
2010	2.8	2.6	6.0	8.8	40.00

SOURCE: GRI 1986 Baseline Projection of U.S. Energy Supply and Demand to 2010 and the CERI Energy Market Analysis Service.

- the purchase cost of housing and household appliances, and gains in equipment efficiency.

Other important factors affecting natural gas demand are government policy and programs directed to promoting conservation. Under the Canadian Oil Substitution Program, the Canadian government subsidized new hook-ups in Ontario and Quebec as part of an "off-oil" policy. The Canadian Home Insulation Program reduced space heating requirements through grants to households to upgrade insulation. Neither of these policies, however, is in effect today. In the U.S., many states restricted new hook-ups in the mid-1970s because of shortages being experienced at the time.

Distillate fuel oil and electricity are the major competitors of natural gas in the residential sector. As mentioned above, the "off-oil" policy of the Canadian government has reduced the competitiveness of fuel oil in the Canadian space heat market. Oil is primarily used in regions lacking the requisite pipeline facilities or where burner-tip gas prices are extremely high because of high transportation costs. Electricity, while it is extremely efficient and clean, is generally high priced relative to gas and does not compete as well in the space heating markets, although in provinces with low electricity rates such as B.C., Manitoba, and Quebec, it still captures a high proportion of the new housing market due to improved technologies like the heat pump and lower installation costs. It is, however, used extensively in fueling household appliances and it is in this market that it competes strongly with gas, as it is a viable alternative for every appliance that natural gas can fuel. Oil is not a factor in this market.

Residential gas demand is generally less responsive to changes in price than are commercial and industrial demand. In economic terms, residential demand is less "price-elastic" than the others. That is, for a given percentage change in price, the percentage change in quantity demanded is smaller than is the case for commercial and industrial demand.[13] Residential demand is restricted in the short run because of the fixed nature of the energy using stock of equipment and housing. Households may decide to upgrade or convert furnaces and/or appliances but only if the present value of the energy savings exceeds the required capital investment. The long payback period for such investments make them less attractive in the residential sector than in the commercial and industrial sectors. In the short term, households are restricted to using energy more or less intensively. It is for these reasons that the residential gas market is referred to as either the "captive" or "core" market in public policy debates.

The only potential growth areas in the residential sector are increased demand through new housing starts and appliance purchases and possibly through the introduction of new gas using technologies. It is likely that the growth due to these factors will be largely offset by increasing efficiency of new appliances and growing conservation awareness.

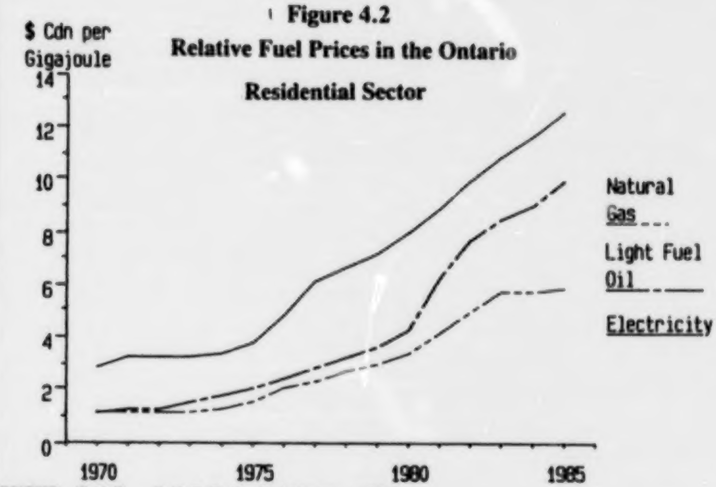
4.4.1 The Canadian Residential Sector

Historically, gas prices have averaged about 50 percent less than electricity prices and 25 percent less than light fuel oil prices. As illustrated in Figure 4.2, natural gas has maintained a relative price advantage over competing fuels in the residential sector since 1970. During this period, natural gas consumption more than doubled in the Western Canadian and Ontario demand regions, as shown in Figure 4.3. Because of the high delivered cost of gas, a relatively underdeveloped distribution system and more competitive alternative fuel prices, the share of natural gas in Eastern Canadian residential energy consumption has remained very low relative to Ontario and Western Canada. In 1985, natural gas consumption in Eastern Canada accounted for only 5 percent of total consumption in the Canadian residential sector. Natural gas consumption in Ontario accounted for 42 percent while consumption in Western Canada made up 52 percent of the total.

Patterns of energy use changed significantly after the OPEC price shock of 1973. Energy use per customer, as illustrated in Figure 4.4, declined sharply after the 1973 increase in oil prices. As real oil prices began to fall between 1973 and 1978, demand per customer increased slightly. The oil price shock of 1978 again induced a considerable conservation effect with demand per customer declining 7 percent between 1978 and 1985.

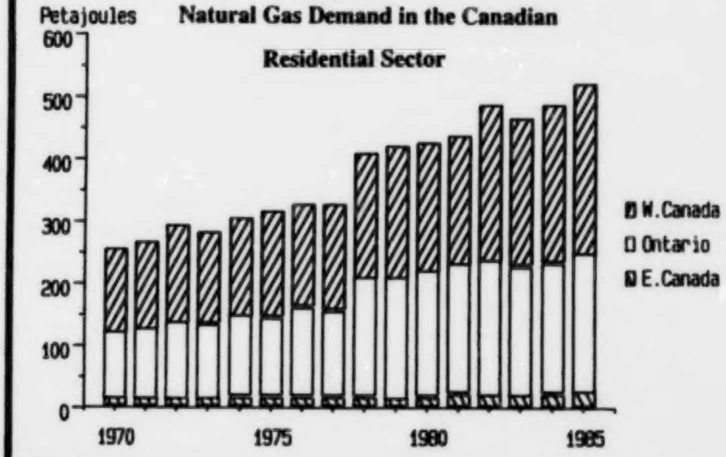
This price-induced conservation was augmented by government sponsored conservation programs. The NEP of 1980 introduced several of these plans. The Canadian Oil Substitution Program (COSP) provided each household or business with grants towards 50 percent of the cost of converting oil-based heating systems to alternative systems, usually to electricity, natural gas, and wood-fueled heating equipment incorporating technical improvements to increase their efficiency. The Canadian Home Insulation Program (CHIP) provided grants to home or

Figure 4.2
Relative Fuel Prices in the Ontario
Residential Sector



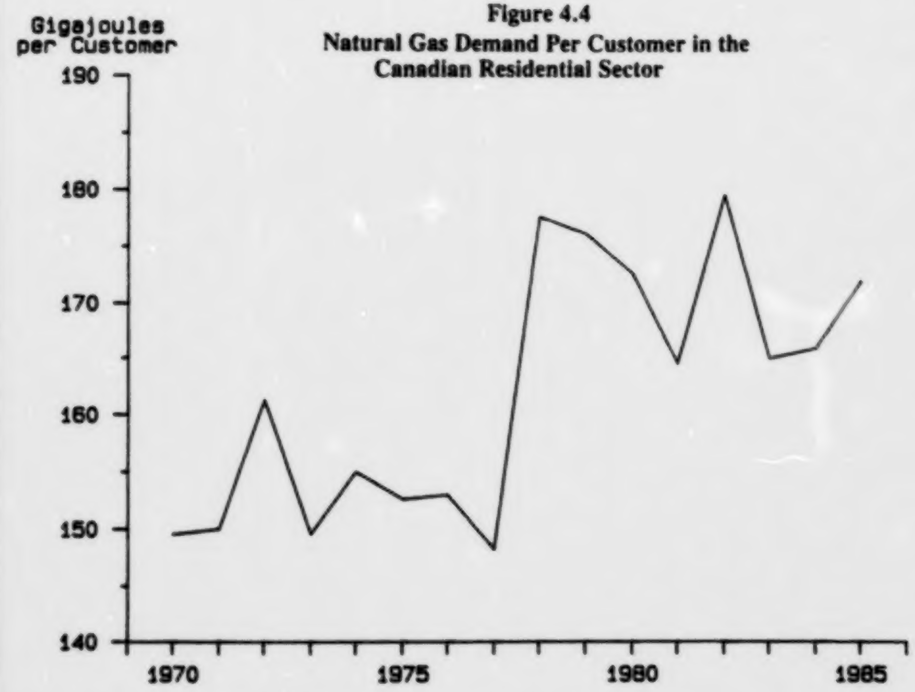
SOURCE: E.M.R., I.F.S.D.M. Database, 1986.

Figure 4.3
Natural Gas Demand in the Canadian
Residential Sector



SOURCE: E.M.R., I.F.S.D.M. Database, 1986.

Figure 4.4
Natural Gas Demand Per Customer in the
Canadian Residential Sector



SOURCE: E.M.R., I.F.S.D.M. Database, 1986.

small apartment owners to help defray the cost of insulation improvement on homes built before 1971. These grants covered 100 percent of materials costs and 50 percent of labour costs. Approximately 2.3 million households obtained grants under the program. Although both of these programs have been discontinued, motivation for conservation and technological improvement remains high.

The CREED forecast of residential sector natural gas demand by region is shown in Table 4.3. Total residential natural gas demand is forecast to increase from 525 petajoules in 1985 to 581 petajoules in 1990 and 785 petajoules in 2010. This translates into an annual average growth rate of slightly less than 2 percent. The share of natural gas in total residential energy consumption is forecast to increase from about 46 percent in 1990 to 50 percent in 2010. This growth is mainly at the expense of light fuel oil whose market share is forecast to decline from about 18 percent of total residential energy consumption in 1990 to about 8 percent in 2010. Electricity's share in total energy consumption also gains at the expense of oil, increasing from about 36 percent in 1990 to 42 percent in 2010.

TABLE 4.3

FORECAST OF RESIDENTIAL SECTOR DEMAND FOR NATURAL GAS IN CANADA

(petajoules)

Year	Eastern Canada	Ontario	Western Canada	Total
1990	38.95	235.68	306.60	581.23
1995	54.46	252.85	328.18	635.49
2000	72.21	264.35	346.04	682.60
2005	91.21	275.97	363.59	730.77
2010	112.21	289.77	383.75	785.73

SOURCE: Canadian Energy Research Institute.

On a regional basis, a large share of the increase in residential natural gas demand is due to increased consumption in Eastern Canada, primarily Quebec. In this region, oil loses market share to both natural gas and electricity. The share of natural gas in total Quebec residential energy consumption is forecast to increase from 11 percent in 1985 to 25 percent in 2010. The share of electricity increases from 56 percent to 67 percent while the share of light fuel oil declines from 33 percent to 8 percent over the same period.

The same type of trend is forecast in Ontario and Western Canada. Light fuel oil's share in total Ontario residential energy demand is forecast to decline from 17 percent in 1985 to 3 percent in 2010. Natural gas and electricity's shares in total energy consumption increase from 53 percent and 33 percent to 57 percent and 41 percent respectively. Similarily, in Western Canada light fuel oil's share in total residential energy demand is forecast to fall from about 6 percent in 1985 to 3 percent in 1990. Electricity's share remains relatively flat, declining only slightly from 25 to 24 percent, while the share for natural gas increases from 69 to 74 percent over the same period.

4.4.2 The U.S. Residential Sector

Historically, natural gas has met 50 percent of energy requirements in the U.S. residential sector. Over the 1970s, annual consumption was relatively constant at about 5000 petajoules as shown in Figure 4.5. The East North Central region holds the largest share of this total but residential gas consumption in this region has fallen 13 percent since 1978. This trend of decreasing residential gas consumption holds in every region of the U.S. with the largest percentage fall occurring in the West South Central region. Demand in the Mid Atlantic/New England region has remained relatively constant at just over 900 petajoules per year.

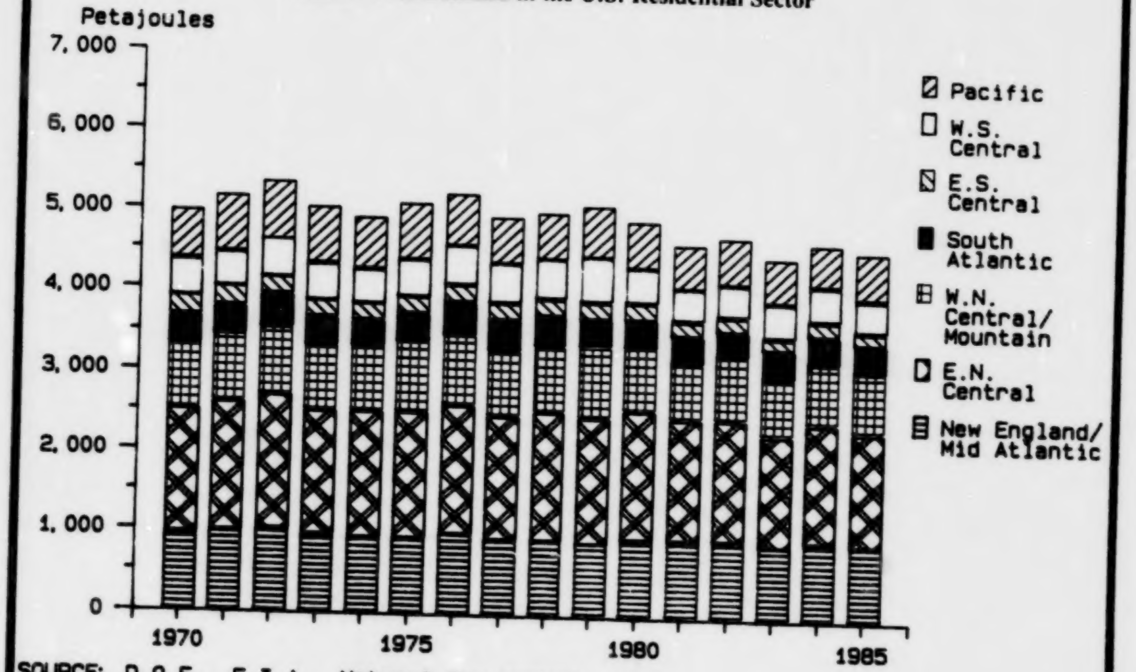
The principal reason for the decrease in residential natural gas consumption over time has been conservation. Natural gas demand per residential customer (see Figure 4.6) has declined 23 percent since 1978. Upgrading of insulation and the use of more efficient furnaces have played important roles in this trend. In addition, new homes are being built with higher insulation standards and are being equipped with more energy efficient appliances and heating equipment.

On average, natural gas prices have remained below the prices of competing fuels in the U.S. residential sector, as illustrated in Figure 4.7. However, these prices mask significant regional trends. In regions such as the Northeastern U.S., where gas costs are quite high because of higher transportation costs, gas faces significant competition from LPGs, fuel oil and wood.

Continued energy conservation is expected to impact strongly on future residential energy consumption. GRI expects conservation of

Figure 4.5

Natural Gas Demand in the U.S. Residential Sector



SOURCE: D.O.E., E.I.A., Natural Gas Annual, 1985.

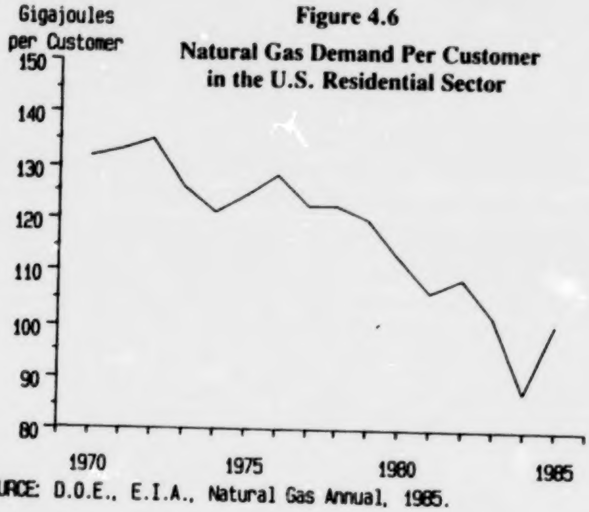


Figure 4.6
Natural Gas Demand Per Customer
in the U.S. Residential Sector

SOURCE: D.O.E., E.I.A., Natural Gas Annual, 1985.

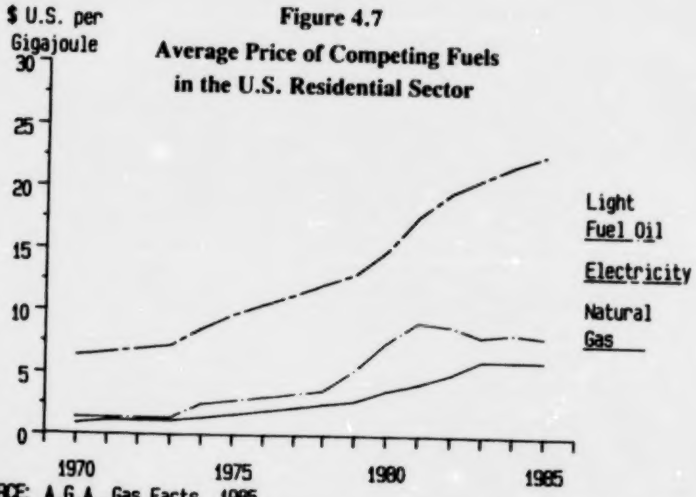


Figure 4.7
Average Price of Competing Fuels
in the U.S. Residential Sector

SOURCE: A.G.A., Gas Facts, 1985.

direct fuel consumption per household to occur at an average rate of 0.6 percent per year from 1985 to 2010 reflecting thermal integrity improvements in the existing housing stock, the replacement of existing space-heating and cooling systems with higher efficiency models, and the addition of more energy efficient homes to the housing stock.

The GRI 1986 Baseline Projection forecasts total residential energy demand to increase quite modestly at only 0.5 percent per year, from 10 200 petajoules in 1985 to 11 600 petajoules in 2010. The growth in projected total residential energy demand occurs in electricity and renewables consumption, which offsets declines in petroleum and gas consumption. Combined residential petroleum and gas consumption declines from 6.2 petajoules in 1985 to 5.4 petajoules in 2010 while electricity and renewable energy consumption increases from 3.9 to 6.1 petajoules over the same period.

Regional shares of total residential energy consumption are expected to change over time. Only the North Central region shows a decline, reflecting a shift in population out of this region. This corresponds to a shift in the U.S. economy to a more service oriented economy and a decline in the importance of old-line heavy manufacturing industries, disproportionately located in the North Central region.

The GRI forecast of natural gas demand by region is shown in Table 4.4 and is consistent with the historical trend of improved conservation. Total gas consumption in the residential sector is expected to decline gradually from 4735 petajoules in 1990 to 4067 petajoules in 2010. Further, gas consumption is expected to fall in every region of the country with the smallest decrease, about 1 percent between 1990 and 2010, occurring in the New England/Mid Atlantic region. The largest decline, about 34 percent between 1990 and 2010, occurs in the East North Central region.

4.5 The Commercial Sector

Commercial natural gas markets share several features with residential markets in that gas is primarily used for space and water heating and its major competitors are distillate fuel oil and electricity. However, unlike the residential sector, natural gas demand in the commercial sector is dependent on the final demand for the variety of services being offered. In recent years, the service industry has been the primary source of economic growth in the U.S. while many of the traditional heavy industries have been in decline. It is shifts in

TABLE 4.4

FORECAST OF NATURAL GAS DEMAND IN THE U.S. RESIDENTIAL SECTOR

(petajoules)

Year	New England/ Mid Atlantic	East North Central	West North Central/Mountain	South Atlantic	East South Central	West South Central	Pacific	Total
1990	950.8	1454.1	752.3	374.5	194.0	438.9	570.1	4734.842
1995	944.9	1358.8	720.5	365.3	190.1	424.1	566.0	4569.789
2000	949.5	1271.5	687.3	353.8	188.0	417.5	566.7	4434.210
2005	933.7	1177.8	642.0	337.5	183.6	410.2	564.4	4249.157
2010	938.5	1081.1	593.2	324.8	175.9	398.1	555.3	4066.842

SOURCE: GRI 1986 Baseline Projection of Energy Demand and Supply.

the structure of the economy such as this that play a large role in determining the derived demand for natural gas in the commercial and industrial sectors. Besides changing patterns in the final demand for goods and services, other factors affecting commercial gas demand include:

- the burner-tip prices of gas and substitute fuels;
- to a lesser extent than in the residential sector, the existing pipeline infrastructure since most commercial construction tends to take place closer to urban areas where gas is more likely to be available;
- the amount of new commercial construction and additional space heating requirements;
- seasonal changes in commercial business activity;
- the existing stock of commercial dwelling and energy using equipment, and their inherent technical characteristics; and
- construction and equipment costs, conservation programs, and gains in energy efficiency.

New gas-using technologies are also likely to impact on future commercial gas demand. In the U.S., gas fired commercial co-generation offers significant opportunities for competitive off-the-shelf, packaged equipment (rather than site-specific, site engineered systems). The introduction of an advanced commercial gas cooling system could also significantly increase gas consumption in the commercial sector.

Most studies of gas demand in the residential and commercial sectors conclude that the commercial sector is more responsive to changes in natural gas prices.[14] The ability of the commercial sector to respond to price changes is largely the result of dual capacity boilers in many commercial buildings that allow short-term switching in response to changing fuel prices. Because fuel costs impact on profit margins, more analysis is directed to fuel choices and the thermal efficiency of energy using equipment. This is reflected in a greater willingness to adopt new practices or purchase new equipment if such analysis indicates it is profitable to do so.

4.5.1 The Canadian Commercial Sector

Natural gas has historically been priced lower than other competing fuels in the commercial sector, about 65 percent lower on average than electricity and about 40 percent lower than light fuel oil (see Figure 4.8). During the period 1970-1985, natural gas consumption in the commercial sector increased from 203 petajoules to 427 petajoules as shown in Figure 4.9. Most of this growth occurred in Ontario, where consumption more than doubled from 85 to 190 petajoules, and Quebec, where consumption increased fivefold from 7 to 38 petajoules over the same period. Western Canada consumes the largest share of natural gas used in the Canadian commercial sector.

A similar trend to the residential sector is also evidenced in commercial natural gas demand per customer (see Figure 4.10). With the decline in real crude oil prices after 1973, commercial sector gas demand per customer increased slightly till 1977 after which it declined quite sharply, by about 15 percent between 1978 and 1985.

The CREED forecast of commercial sector natural gas demand by region is shown in Table 4.5. In all three regions, growth in total sectoral energy consumption reflects the gradual shift expected in Canada's economy to a more service oriented economy. Growth in gas sales is expected in the commercial sector in all regions. As in the residential sector, fuel oil loses market share to both natural gas and electricity. In Quebec, fuel oil's share in total commercial energy consumption is expected to decline from 29 percent in 1985 to 3 percent in 2010. Natural gas and electricity's shares increase from 26 and 48 percent to 29 and 69, respectively, over the same period. Consumption in the Eastern Canadian commercial sector is expected to nearly double between 1990 and 2010 from 57 petajoules to 107 petajoules.

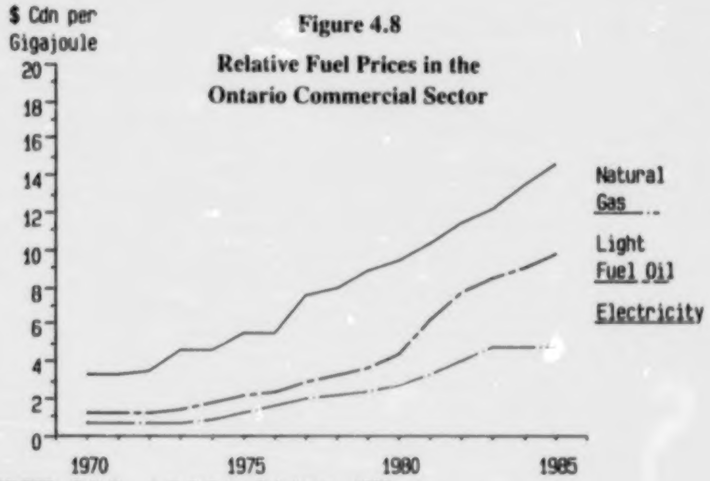


Figure 4.8

Relative Fuel Prices in the Ontario Commercial Sector

SOURCE: E.M.R., I.F.S.D.M. Database, 1986.

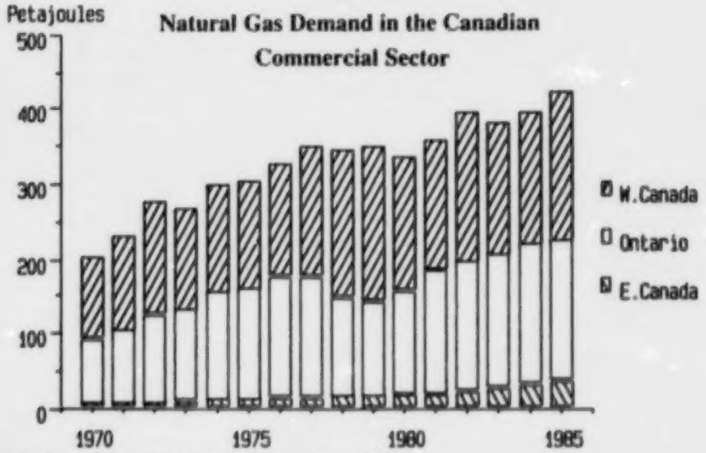


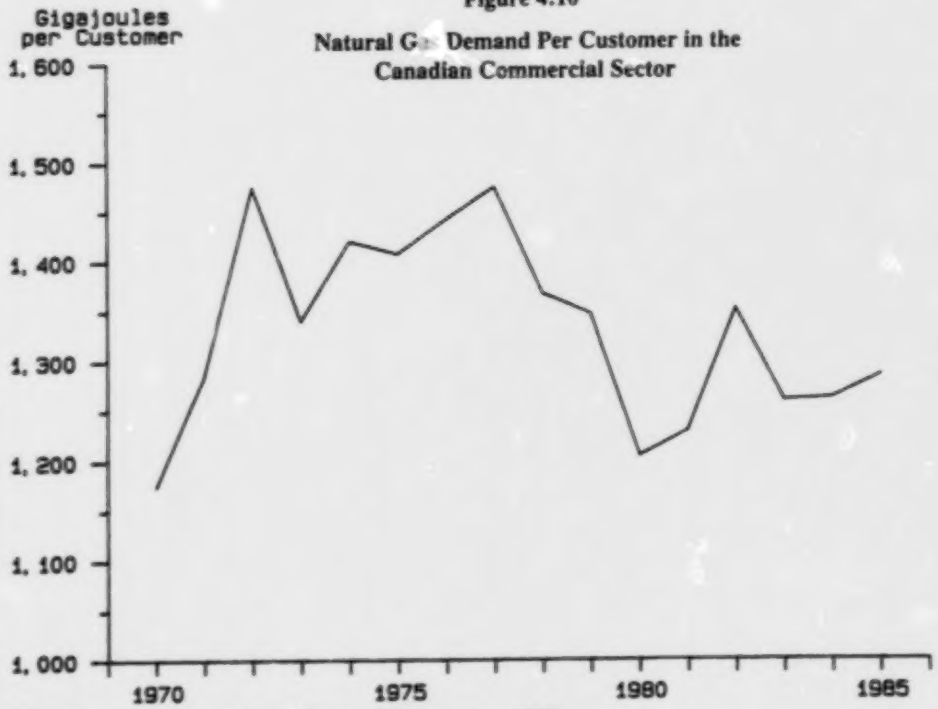
Figure 4.9

Natural Gas Demand in the Canadian Commercial Sector

SOURCE: E.M.R., I.F.S.D.M. Database, 1986.

Figure 4.10

Natural Gas Demand Per Customer in the Canadian Commercial Sector



SOURCE: E.M.R., I.F.S.D.M. Database, 1986.

TABLE 4.5

FORECAST OF COMMERCIAL SECTOR DEMAND FOR NATURAL GAS IN CANADA

(petajoules)

Year	Eastern Canada	Ontario	Western Canada	Total
1990	56.84	251.32	250.81	558.97
1995	65.39	287.07	295.40	647.86
2000	77.66	323.98	326.65	728.29
2005	91.73	374.08	362.57	828.38
2010	107.19	441.06	416.46	964.72

SOURCE: Canadian Energy Research Institute.

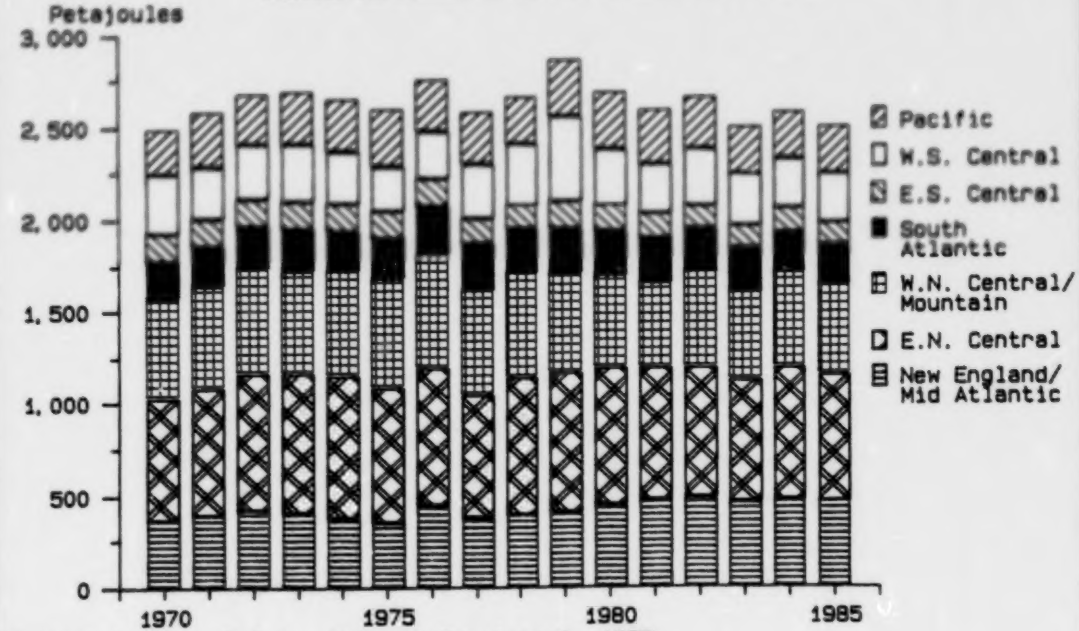
Growth in the commercial sector of Ontario's economy is reflected in the forecast of growth in the region's natural gas consumption. Commercial sector demand is forecast to increase 75 percent between 1985 and 2010, from 251 to 441 petajoules. Natural gas and electricity's share in total sectoral energy consumption increases from 53 and 34 percent in 1985 to 58 and 37 percent in 2010 respectively. These gains are largely achieved at the expense of fuel oil, whose share declines from 13 percent to 5 percent over the same period.

Growth in natural gas demand in the Western Canadian commercial sector is expected to be lower than in Ontario, increasing from 251 to 416 petajoules between 1990 and 2010. The share of natural gas in total sectoral energy consumption is forecast to increase from 54 to 63 percent between 1985 and 1990 at the expense of fuel oil whose share declines from 20 to 11 percent over the same period. Electricity's share remains relatively constant at 26 percent.

4.5.2 The U.S. Commercial Sector

In 1984, over 43 percent of total energy demand in the commercial sector was met by natural gas, with electricity's share slightly lower at 38 percent. Through the 1970s, total commercial sector gas consumption averaged close to 2700 petajoules annually (see Figure 4.11). The East North Central region has the largest regional share with the West North Central and New England/Mid Atlantic regions close behind. As in the residential sector, total gas consumption in the commercial sector has been declining over the past 7 years. However,

Figure 4.11
Natural Gas Demand in the U.S. Commercial Sector



SOURCE: D.O.E., E.I.A., Natural Gas Annual, 1985.

unlike the residential sector, some regions have shown growth over the 1970 to 1985 period. These regions include the Pacific, South Atlantic, East North Central, and New England/Mid Atlantic region. Growth was particularly strong in the latter region.

Conservation in energy use has also played a major role in the decline in total commercial gas consumption. As illustrated in Figure 4.12, gas demand per commercial customer in 1985 has declined 28 percent from the peak year observed in 1980. This follows the trend to more energy efficient buildings, furnaces, and appliances.

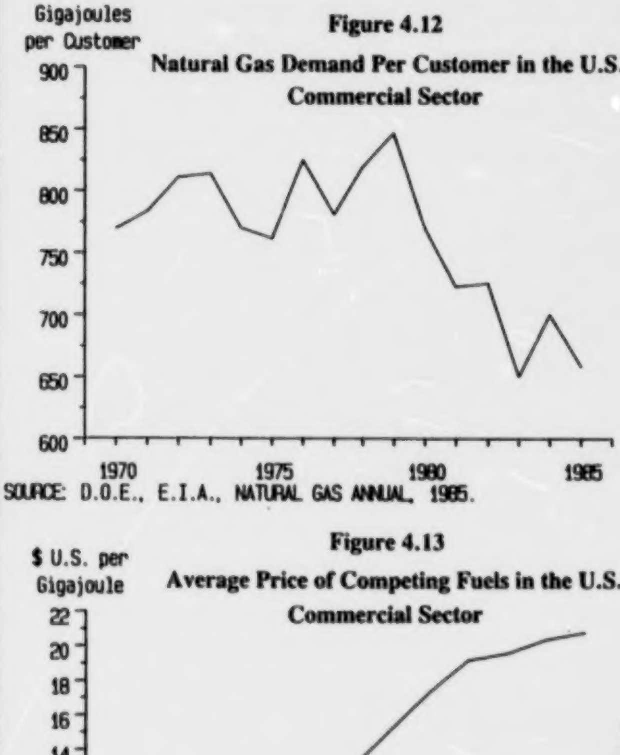
As in the residential sector, natural gas has maintained a price advantage over its principal competitors--electricity and light (No. 2) fuel oil--in the commercial sector, as illustrated in Figure 4.13. Again, this masks regional trends where, because of high transportation costs, gas is relatively less competitive with fuel oil, especially in regions where refining capacity is high.

Total commercial energy consumption is projected by the GRI to grow from 6.4 exajoules in 1985 to 9.2 exajoules in 2010. This growth reflects the reorientation of the U.S. economy towards a more service-based economy. Increased gas and electricity consumption constitute the majority of growth in total commercial energy demand. Electricity consumption is projected to increase from 2.4 exajoules in 1985 to 3.8 exajoules in 2010. Much of the growth in electricity consumption is accounted for by growth in electricity demand for lighting and "other" electric appliances. Very little growth is expected in electricity consumption for space heating and cooling.

Unlike the residential sector, the commercial sector represents a potential growth market for natural gas. Consumption is expectd to increase from 2.6 exajoules in 1985 to 3.8 exajoules in 2010 as shown in Table 4.6. On a regional basis, the Pacific and West South Central regions are projected to have the greatest potential for commercial gas consumption increases. Between 1990 and 2010, gas consumption is expected to increase 68 percent in these regions, from 306 petajoules to 517 petajoules in the West South Central region and from 318 petajoules to 527 petajoules in the Pacific region. The New England/Mid Atlantic region is also identified as a potential growth area with commercial gas consumption projected to increase 40 percent between 1990 and 2010, from 502 petajoules to 748 petajoules.

Figure 4.12

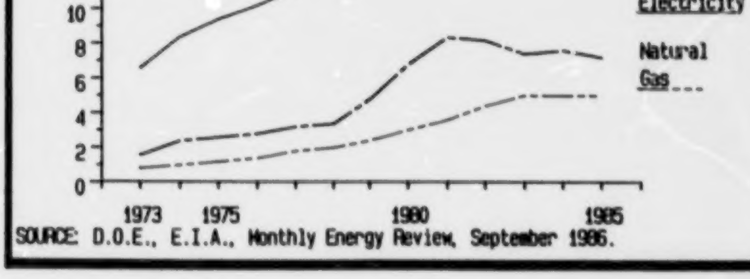
Natural Gas Demand Per Customer in the U.S. Commercial Sector



SOURCE: D.O.E., E.I.A., NATURAL GAS ANNUAL, 1985.

Figure 4.13

Average Price of Competing Fuels in the U.S. Commercial Sector



SOURCE: D.O.E., E.I.A., Monthly Energy Review, September 1986.

TABLE 4.6
FORECAST OF NATURAL GAS DEMAND IN THE COMMERCIAL SECTOR
(petajoules)

Year	New England/ Mid Atlantic	East North Central	West North Central/Mountain	South Atlantic	East South Central	West South Central	Pacific	Total
1990	502.3	716.5	524.6	267.4	138.5	306.0	317.7	2773.1
1995	562.1	721.4	555.9	306.6	151.9	356.3	372.5	3026.7
2000	615.2	724.0	583.8	340.6	165.6	413.9	429.7	3272.7
2005	668.6	727.3	603.7	369.2	178.5	466.3	477.6	3491.2
2010	747.5	742.2	628.2	403.3	195.1	517.3	526.6	3760.1

SOURCE: GRI 1986 Baseline Projection of Energy Demand and Supply.

A significant proportion of the projected gas consumption growth in the 1986 GRI Baseline Projection is due to the inclusion of gas-fired cogeneration. This estimate is projected at net 420 trillion Btus of gas fired commercial cogeneration in the year 2000 and at net 570 trillion Btus in 2010. A large portion of this market is in off-the-shelf packaged equipment, rather than site-specific engineered systems. A potential area of growth for gas consumption that was not included in the Baseline Projection is space cooling with gas fired or engine driven absorption chillers, technologies that GRI is currently researching.

4.6 The Industrial Sector

In both Canada and the U.S., the industrial sector makes up the largest component of total natural gas demand. This sector is also the most vulnerable to competing fuels because of the high degree of dual-fired capacity present within it. Gas demand is derived from the demand for goods and services and will vary depending on seasonal changes in business activity and longer term structure.

A major difference between the residential/commercial and the industrial sectors is the multiplicity of applications for natural gas in the latter. It is used as a feedstock in the petrochemical industry, as a fuel by the electricity generating industry, and to provide process heat in industrial applications. The two largest segments of the industrial market are boilers and direct process heat applications such as furnaces, kilns, dryers, and heaters.

Natural gas faces strong interfuel competition from both distillate and residual fuel oils, coal, and electricity. The nature of this competition depends very specifically on the energy using technologies of the different industry groups, regional environmental standards, relative prices, and the capital and operating costs associated with differently fuelled equipment. Coal has a considerable cost advantage on a Btu basis over all other fuels, especially in large applications. In the boiler market, despite coal's price advantage, natural gas remains a viable option in many instances. Capital and operating costs are much higher for coal than comparably sized gas units. Coal boilers require special materials, handling equipment, environmental control equipment, and waste-disposal equipment. Natural gas boilers emit only a fraction of the sulphur dioxides, nitrogen oxides, and particulates produced by coal boilers. Currently, residual fuel oil is the major competitor to gas in the boiler market. As long as the sulphur content of the oil alternative meets applicable clean air standards, customers are largely indifferent between the two fuels and the choice depends on relative prices and security of supply.

In the process heat market, energy inputs into furnaces provide a number of services such as reheating steel, smelting ore, heating fluids, and drying a variety of substances. Natural gas is the dominant energy source for process heating but coal, electricity, and fuel oil (mainly distillate) are also used. Coal's cost advantage in this market is offset for many of the reasons outlined above and because current technology does not offer adequate control of temperature in many applications. Electricity competes in the process heat market primarily on the basis of its unique capabilities and excellent control characteristics.

Gas is also used as a primary fuel in the generation of electricity. Its major competitors in this market are coal and residual fuel oil. Coal, as before, has a considerable cost advantage but clean air restrictions and other disadvantages cause it to be used primarily in larger electricity generating plants. In smaller plants supplying peaking power, oil and gas are the major competitors and compete primarily on a Btu basis. While residual fuel oil is slightly more efficient than gas, gas recovers part of this disadvantage through lower nonfuel operating costs.

Natural gas demand in the industrial sector is much more responsive in the short term to changes in relative fuel prices. This is a result of the significant amount of dual-fired capacity present within all segments of the sector. It is in the boiler market that most of the dual-fired capacity in the U.S. exists. In 1982, GRI estimated that if gas prices just exceeded residual fuel oil prices, the industry had the capability of switching 1.6 exajoules of gas use to residual fuel oil within a 6-month time frame. In electric utilities, the study indicated that about 2.4 exajoules of total gas demand could be replaced by low-sulphur residual fuel oil.[15]

Table 4.7 shows the proportion of the market that is vulnerable to fuel switching on an instantaneous basis. The estimated fuel switchable market is consistent in magnitude with GRI's estimate. Regionally, over 40 percent of the fuel switchable market is located in the West South Central region and over 17 percent is located in the Pacific Southwest or California region.

TABLE 4.7

U.S. NATURAL GAS CONSUMPTION (1986) AND PROPORTION OF MARKET VULNERABLE TO FUEL SWITCHING TO NO. 6 & NO. 2 FUEL OIL

(billion cubic feet)

	Natural Gas Consumption					Fuel Switchable Market			
	Residential	Commercial	Industrial	Electric Utility	Total	No. 6 Fuel Oil		No. 2 Fuel Oil	
						Volume	Percent	Volume	Percent
New England	171	91	50	16	328	57	17	3	1
Mid-Atlantic	759	359	316	171	1 605	289	18	13	1
East North Central	1 392	611	771	20	2 794	324	12	18	1
West North Central	426	288	309	21	1 044	122	12	6	1
South Atlantic	344	215	447	182	1 188	345	29	28	2
East South Central	172	108	306	49	635	126	20	21	3
West South Central	346	216	2 429	1 600	4 591	1 302	28	43	1
Mountain	236	161	95	63	555	72	13	6	1
Pacific Southwest	490	216	345	444	1 495	558	37	5	—
Pacific Northwest	56	56	100	--	212	51	24	—	—
Total	4 392	2 322	5 168	2 568	14 450	3 246	22%	143	1%
Pipeline Fuel					480	—	—	—	—
Field Use					947	—	—	—	—
Total U.S. Consumption					15 877	3 246	20%	143	1%

SOURCE: U.S. Department of Energy/Energy Information Administration, "Natural Gas Monthly," and fuel switching estimates made by Foster Associates, Inc., Tenneco and Texas Eastern Co.

Industrial gas demand is also much more reponsive in the medium and longer terms. Decision makers in industry who choose among competing fuels are more informed about current and possible future market conditions and devote considerable time to analysing alternative fuels and fuel using technologies. Compared to the multitude of individuals comprising the residential and commercial markets, these decision makers are more capable and more likely to make decisions warranted by their analysis.

In the future, energy demand in the industrial sector will continue to depend on the final demand for goods and services produced within it. Changing consumption patterns and world trade flows will continually impact on energy demand within the various industry groups. To a large extent, gas demand will depend on the development of new end use technologies. Such new technologies will have to enhance the inherent advantages of gas and increase the efficiency of gas use for gas to maintain a strong position in the industrial market. Moreover, technological improvements in coal and electricity process applications are likely to maintain the competitive position of these fuels. Industrial cogeneration of electricity has and will continue to provide opportunities for increased gas usage and may prove that on site gas-fired cogeneration facilities are the best way to provide process electricity. In any event, the industrial sector will continue to be the most highly competitive and dynamic of the three sectors.

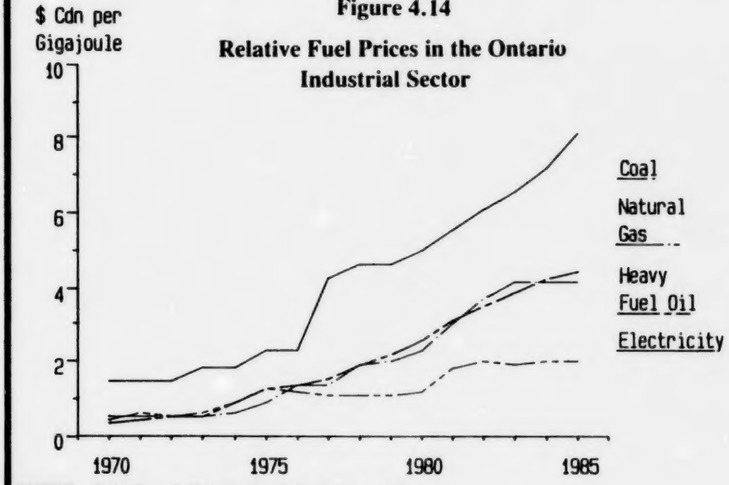
4.6.1 The Canadian Industrial Sector

Natural gas faces much stiffer price competition in the Canadian industrial sector as illustrated in Figure 4.14. Historically, natural gas has been priced at about 90 percent Btu equivalence of residual fuel oil, its major competitor. Coal, which is likely to be a principal competitor in the future, has traditionally been priced lower than natural gas but problems in its usage (described above) have made it difficult to obtain significant market share.

The industrial sector has historically been the largest gas consuming sector in Canada. As shown in Figure 4.15, the size of Ontario's manufacturing sector makes it the largest consuming region of natural gas in the industrial sector. Growth in natural gas consumption in the Canadian industrial sector has not been as rapid as in the residential and commercial sectors except in Eastern Canada. Consumption in Eastern Canada increased fourfold from 1970 to 1985 from 31 petajoules to 119 petajoules. Ontario consumption increased 37 percent

Figure 4.14

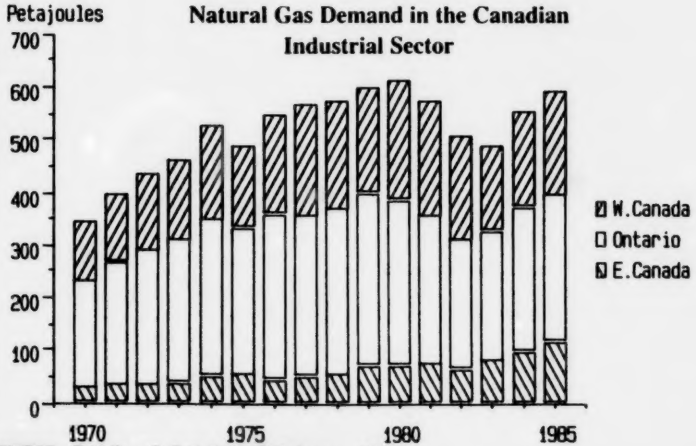
Relative Fuel Prices in the Ontario Industrial Sector



SOURCE: E.M.R., I.F.S.D.M. Database, 1986.

Figure 4.15

Natural Gas Demand in the Canadian Industrial Sector



SOURCE: E.M.R., I.F.S.D.M. Database, 1986.

over the same period from 205 to 281 petajoules while Western Canadian consumption increased 72 percent from 113 to 195 petajoules.

As shown in Figure 4.16, natural gas demand per industrial customer generally increased from 1970 to 1980. A sharp increase between 1978 and 1980 reflects the substitution away from oil by industrial users following the 1978 oil price shock. Since 1980, demand per customer has declined by 12 percent.

The CREED forecast of industrial sector demand by region is presented in Table 4.8. Eastern Canadian natural gas demand (primarily Quebec) is expected to nearly double between 1990 and 2010 from 168 to 311 petajoules. The share of natural gas in this region's total industrial energy demand is expected to increase from 22 percent in 1985 to 28 percent in 2010. Electricity's share increases from 58 to 64 percent while residual fuel oil loses share, from 20 to 8 percent, over the same period.

TABLE 4.8

FORECAST OF INDUSTRIAL SECTOR DEMAND FOR NATURAL GAS IN CANADA
(petajoules)

Year	Eastern Canada	Ontario	Western Canada	Total
1990	167.67	358.98	587.61	1114.26
1995	204.78	421.40	633.47	1259.65
2000	229.18	465.41	677.38	1371.97
2005	264.65	511.54	730.02	1506.21
2010	311.44	568.16	792.42	1672.02

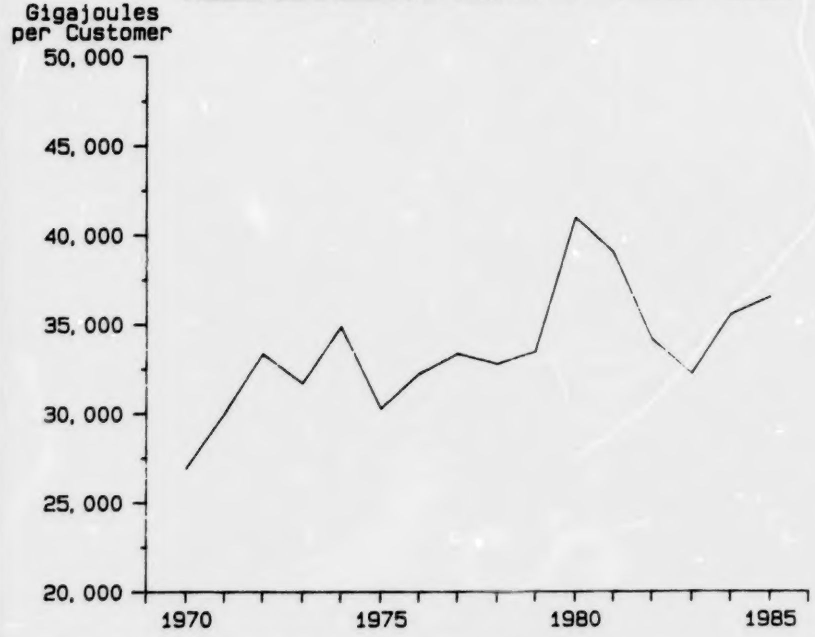
SOURCE: Canadian Energy Research Institute.

NOTE: Industrial natural gas demand includes natural gas used as feedstock.

Industrial gas demand in Ontario is expected to increase 58 percent over the forecast horizon from 359 petajoules in 1990 to 568 petajoules in 2010. The share of natural gas in total industrial energy consumption is forecast to increase slightly from 56 to 60 percent as is that of electricity, from 32 to 35 percent. The share of residual fuel oil decreases from 12 to 5 percent over the same period.

Figure 4.16

Natural Gas Demand Per Customer in the Canadian Industrial Sector



SOURCE: E.M.R., I.F.S.D.M. Database, 1986.

Forecast trends in Western Canada are similar, with gas consumption increasing from 588 petajoules in 1990 to 792 petajoules in 2010. Natural gas and electricity shares in total industrial energy consumption are expected to increase slightly from 49 and 31 percent in 1985, to 59 and 33 percent in 2010, respectively. The share of residual fuel oil again declines, from 20 to 13 percent over the same period.

4.6.2 The U.S. Industrial Sector

As in Canada, the industrial sector holds the largest sectoral share in total U.S. natural gas consumption at about 55 percent (including natural gas used by electric utilities). Industrial gas demand peaked in 1973 at 9.2 exajoules as illustrated in Figure 4.17, and has subsequently declined to 6.1 exajoules in 1985. This reflects the decline in U.S. industrial sector growth and increased competition from alternative fuels, mainly residual fuel oil. This is particularly evident in the East North Central region, the heartland of U.S. industry, where industrial gas consumption fell 45 percent from a peak of 1.7 exajoules in 1973 to 1.1 exajoules in 1985. All other regions showed a similar decline, although not as great in percentage terms.

A similar trend is evidenced in the electric utility sector (Figure 4.18) where total gas consumption declined from 4.2 exajoules in 1972 to 3.2 exajoules in 1985. This national trend, however, masks some interesting regional trends. As in the industrial sector, the East North Central region suffered a large loss in electric utility gas consumption, from 292 petajoules in 1971 to 29 petajoules in 1985. The West North Central/Mountain and South Atlantic regions suffered similar load losses, from 651 and 361 petajoules in 1970 to 116.8 and 187.3 petajoules in 1985, respectively. The New England/Mid Atlantic was the only region to enjoy significant growth, with gas consumption in electric generation increasing from 108 petajoules in 1973 to 300 petajoules in 1985.

Figure 4.19 shows the average prices of competing fuels in the industrial and electric utility sectors. Residual fuel oil has traditionally not been as competitively priced with natural gas as within the Canadian industrial sector, due to the wellhead price ceilings that were in effect until 1978. The removal of the price ceilings in 1978, in combination with falling oil prices, considerably narrowed the gap between oil and gas prices. Coal is the lowest priced fuel but with the exception of its importance in electricity generation, its inherent

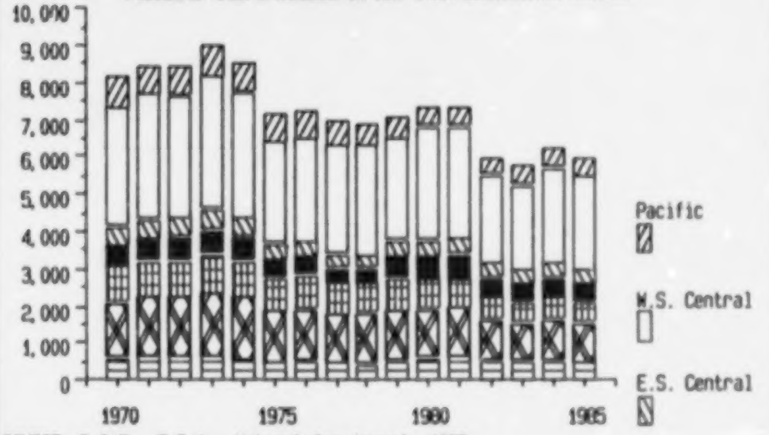


Figure 4.17
Natural Gas Demand in the U.S. Industrial Sector

SOURCE: D.O.E., E.I.A., Natural Gas Annual, 1985.

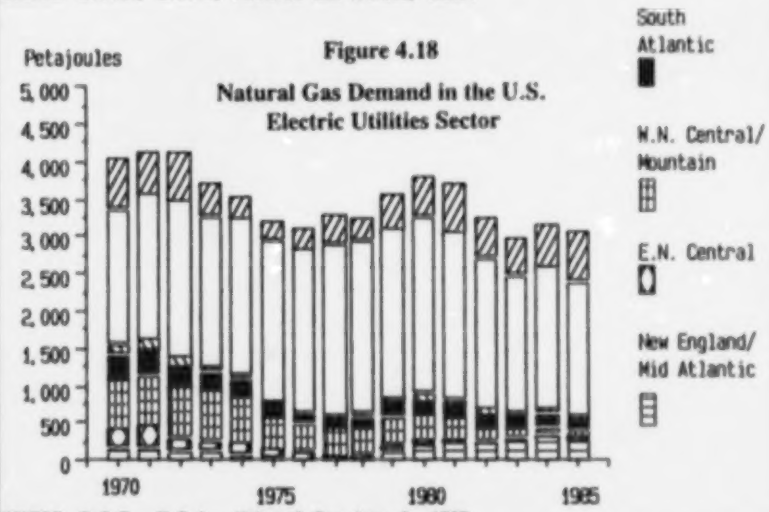
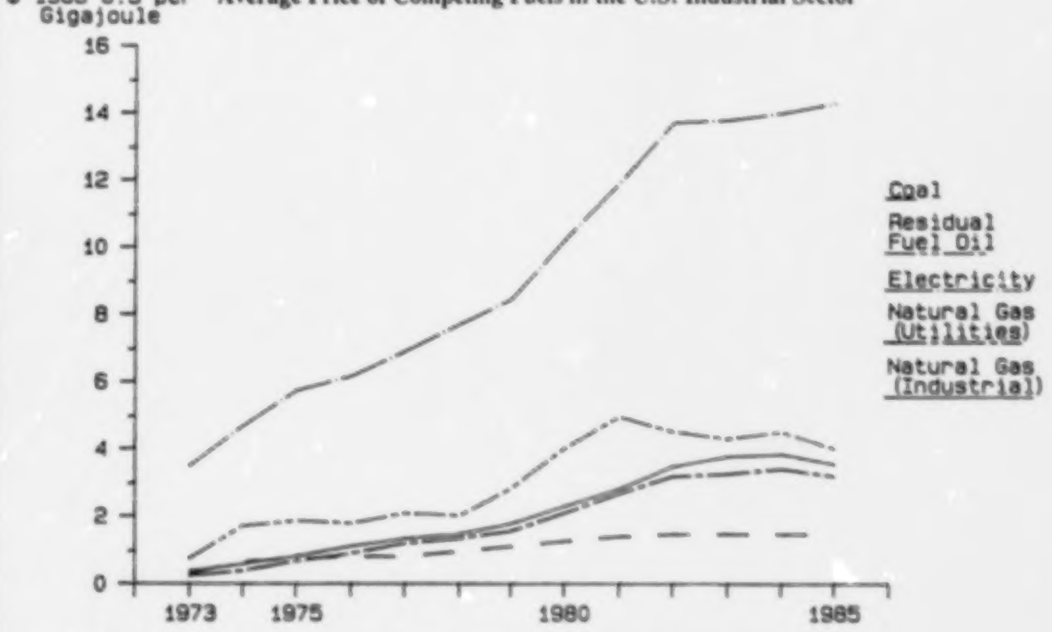


Figure 4.18
Natural Gas Demand in the U.S. Electric Utilities Sector

SOURCE: D.O.E., E.I.A., Natural Gas Annual, 1985.

Figure 4.19

Average Price of Competing Fuels in the U.S. Industrial Sector



SOURCE: D.O.E., E.I.A., Monthly Energy Review, September, 1986.

properties (discussed above) have prevented it from gaining significant share in the industrial sector.

The 1986 GRI Baseline Projection forecasts that total industrial fuel and power consumption will grow at an average rate of 1.6 percent per year, from 18.1 exajoules in 1985 to 26.7 exajoules in 2010. In response to low oil prices in the near term, petroleum consumption is projected to grow quite rapidly, at 4.0 percent per year, from 4.8 exajoules in 1985 to 5.9 exajoules in 1990. Increasing oil prices after 1990 slow the growth in consumption to 1.5 percent per year, from 5.9 exajoules in 1990 to 7.9 exajoules in 2010. Total industrial electricity consumption is projected to grow from 3.3 exajoules in 1985 to 6.0 exajoules in 2010. Coal consumption is expected to increase at an average rate of 4.2 percent per year, from 1.6 exajoules in 1985 to 4.4 exajoules in 2010.

Natural gas is expected to face very different competitive pressures within the near and long term time frames of the projection. In the near term, gas faces strong competitive pressure from residual fuel oil because of low crude oil prices. Although gas is currently priced quite competitively on the spot market, if gas prices rise to cover replacement costs, residual fuel oil could have a price advantage over natural gas though the mid-1990s. For gas to remain competitive once supplies tighten, flexible pricing provisions will be required in contracts between producers, pipelines, distributors and industrial users. Some load loss, however, is possible in the near to medium term.

In the longer term, gas faces increased technological competition. Although gas currently dominates the direct heat market, electricity is projected to gain an increasing share of that market at the expense of gas. Coal is expected to begin penetration in the boiler markets due to technological improvements in thermal efficiency and pollution control, and a healthy price advantage.

As a result of these factors, GRI projects the industrial consumption of gas to be relatively flat (see Table 4.9) at about 6.3 petajoules between 1985 and 2010 after a temporary decline in 1986 and 1987. Gas consumption falls most dramatically in the East North Central and West North Central/Mountain regions, from 1069 and 443 petajoules in 1985 to 771 and 200 petajoules in 2010, respectively. Other regions generally show modest growth. Offsetting a decline in natural gas usage for boiler and direct heat markets in the Pacific

TABLE 4.9

FORECAST OF NATURAL GAS DEMAND IN THE U.S. INDUSTRIAL SECTOR

(petajoules)

Year	New England/ Mid Atlantic	East North Central	West North Central/Mountain	South Atlantic	East South Central	West South Central	Pacific	Total
1990	499.1	1068.6	442.7	545.7	423.6	2394.7	566.8	5941.3
1995	516.7	963.3	383.1	595.4	414.8	2579.9	618.0	6071.2
2000	517.7	873.3	311.7	600.2	406.9	2697.2	637.1	6044.0
2005	503.3	798.4	242.2	593.1	398.6	2750.3	624.4	5910.3
2010	536.1	770.9	199.7	630.5	402.0	2755.4	617.3	5911.9

SOURCE: GRI 1986 Baseline Projection of Energy Demand and Supply.

TABLE 4.10
FORECAST OF NATURAL GAS DEMAND IN THE U.S. ELECTRIC UTILITIES SECTOR
(petajoules)

Year	New England/ Mid Atlantic	East North Central	West North Central/Mountain	South Atlantic	East South Central	West South Central	Pacific	Total
1990	180.6	0.6	21.2	195.2	23.1	1528.2	686.3	2635.2
1995	374.9	5.6	74.1	373.3	23.1	1548.8	926.4	3326.2
2000	473.4	69.9	97.2	398.1	127.7	1936.6	1002.7	4105.6
2005	502.4	73.7	86.6	365.6	166.7	1906.1	990.3	4091.5
2010	547.1	86.2	87.6	412.8	208.2	1777.1	981.2	4127.2

SOURCE: GRI 1986 Baseline Projection of Energy Demand and Supply.

region is a significant growth in natural gas use in enhanced oil recovery operations in central California's heavy oil fields.

Table 4.10 presents GRI's projection of natural gas consumption in the electric utility sector to 2010. This sector holds great promise for increased natural gas consumption in the long term. Total U.S. gas consumption is expected to increase from 2635 petajoules in 1990 to 4127 petajoules in 2010. However, in the short term, total utility gas demand is likely to decline sharply because of new nuclear and coal fired facilities that are due to come on line in the next two years and strong price competition from residual fuel oil.

In the longer term, gas consumption is expected to recover in the mid-to-late 1990s in response to short lead-time requirements for capacity additions as reserve margins tighten in some regions of the U.S. Much of this consumption will be in gas-fired combined cycle facilities. Certain characteristics of this process, most notably the low installed cost, short construction lead times (2 to 3 years) and high thermal efficiency, make it a particularly attractive solution to many of the problems the electric utility sector will face in the future, even when fired with a premium fuel like gas. After 2000, consumption flattens out as more coal fired capacity is added.

On a regional basis, significant growth is expected in the New England/Mid Atlantic region where gas consumption is expected to increase over 200 percent, from 181 petajoules in 1990 to 574 petajoules in 2010. More modest growth is expected in every other region in the U.S. It should be noted that electricity exports from B.C., Manitoba, and Quebec are likely to compete vigorously for a share of this market. Hydro exports from Quebec, in particular, could reduce the need for additional generating capacity in the New England/Mid Atlantic region.

Footnotes

[1] This is a rough form of Ramsey pricing which is useful when prices equal to marginal costs cannot provide the revenues required for a regulated utility. Essentially it implies that the regulator should adjust prices to minimize distortions in consumption. Thus the largest price adjustments should be imposed on those customers who are least likely to change consumption patterns. This concept is discussed in more detail in C. C. Blaydon, "State Policies Under Pressure," in Drawing the Line on Natural Gas Deregulation, The Harvard Study on the Future of Natural Gas, edited by J. P. Kalt and F. C. Schuller (Quorum Books: New York, 1987), pp. 157-170.

[2] Royal Bank of Canada, Global Energy and Minerals Group, The North American Natural Gas Industry (Calgary: 1984), p. 110.

[3] This issue was discussed in more detail in Chapter 2. Essentially Ontario and Manitoba have objected to the high prices being offered by WGML for core market users in light of the discounts being received by industrial users. Ontario has specifically objected to the streaming of lower gas prices to industrial users in recent contracts between WGML and Ontario distributors. Manitoba objected to the average price being offered by WGML and went so far as to arrange a direct sales contract with Alberta producers at substantially lower prices to displace WGML sales. The NEB subsequently refused Manitoba's request for transportation on TCPL on the basis that the direct sale was a vehicle for self displacement. Contracts between WGML and Manitoba's provincial distributors have since been renegotiated at a considerably lower price.

[4] United States, Department of Energy, Energy Information Administration, A Chronology of Major Oil and Gas Regulations Issued Through October 1985 (Washington D.C.: EIA, 1986), p. 25.

[5] C. C. Blaydon, "State Policies Under Pressure," op. cit., p. 159.

[6] Order 380, issued in the fall of 1984, attempted to put pressure on pipelines to renegotiate problem contracts with producers and essentially relieved LDCs and their customers of minimum bill requirements (as discussed in Chapter 2). This afforded LDCs considerably more scope in their purchasing practices. The CD conversion provision in Order 500, which allows an LDC to transfer contract demand volumes to firm transportation service, has further enhanced this flexibility.

[7] Most states importing Canadian gas have implemented some sort of transportation service on their LDCs. However, the type of rates being charged and actual cost vary considerably by state.

[8] A good example is a utility in Illinois, Central Illonois Light, which currently charges $0.70 per Mcf to transport three miles (Natural Gas Intelligence, vol. 6, no. 50, September 7, 1987).

[9] In the above case, the utility has promised to come up with a coal competitive rate to avert the threat of bypass.

[10] For a detailed description of the methodology and structure of the CREED model, see L. Coad, CERI Energy Pricing and Demand Models: A Description and Internal Evaluation, Working paper 87-3 (Calgary: CERI, October 1984).

[11] A detailed description of the Baseline methodology and underlying assumptions are contained in the Gas Research Institute, Gas Research Insights: 1986 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010 (Chicago: GRI, December 1986), pp. 59-86.

[12] At the time of the 1986 Baseline Projection was formulated, liberal waivers had all but rendered the Fuel Use Act (FUA) obsolete and, on this assumption, oil and gas fired facilities above and beyond those already planned by electric utilities were considered explicitly. Specifically, the new assumption allows for oil and gas (including gas-fired combined cycle facilities) as options for new generating capacity, provides for the life extension of existing generating facilities, and accounts for load management in an explicit fashion using load duration curves. The FUA was repealed by Congress in May, 1987.

[13] D. R. Bohi, Analyzing Demand Behaviour: A Study of Energy Elasticities (Baltimore: John Hopkins University Press, 1981) p. 32.

[14] Ibid., p. 69.

[15] R. H. Hilt and H. R. Linden, "Fuel Switching by Industrial and Electric Utility Gas Users: An Overlooked National Issue," Public Utilities Fortnightly (June 10, 1982), p. 6. It should be noted that this study does not consider if sufficient supplies of residual fuel oil are, or will be, available to all who desire to switch from gas.

PART II

Chapter 5

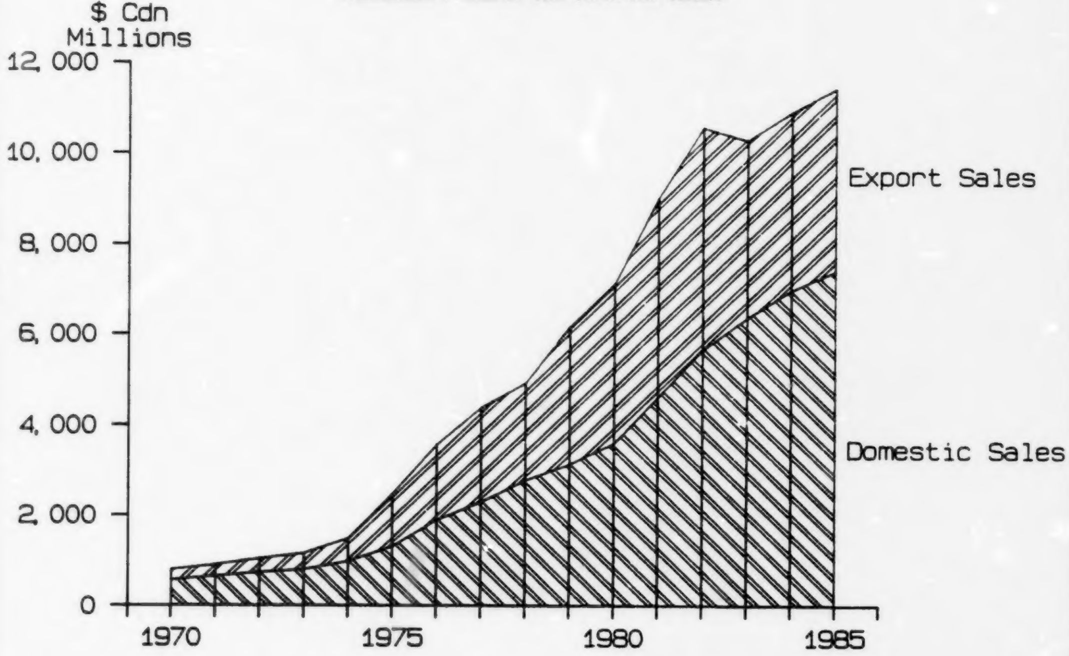
THE NATURAL GAS EXPORT MARKET

Canadian natural gas exports to the United States have played a key role in the development of the Canadian gas industry. As Figure 5.1 illustrates, export sales since 1970 have consistently exceeded 35 percent of total Canadian gas sales on a revenue basis. In 1980, revenue from export sales actually exceeded 1980 gross domestic utility sales. While these figures indicate the historical importance of gas exports to the natural gas industry as a whole and to the Canadian economy, they understate the importance of exports to the gas producing sector. Since export prices have generally been higher than domestic prices over the past 10 years, they have provided considerable stimulus to domestic exploration and development activity.[1]

Recently, the export market has weakened. U.S. importers purchased only 740 Bcf in 1986, down from 940 Bcf in 1985. During this period, prices and revenue from exports declined from an average of \$3.20 (U.S.) per Mcf and 2.95 billion (\$U.S.) in 1985 to \$2.47 (U.S.) per Mcf and 1.83 billion (\$U.S.) respectively in 1986. Figures released for the 1986/1987 contract year (November 1986 to October 1987) indicate that the export market has rebounded slightly. Export volumes increased over 20 percent to 920 Bcf but the average export price and revenue declined 25 percent to \$2.00 per MMBtu (\$U.S.) and 10 percent to \$1.83 million (\$U.S.), respectively, over the same period last year.

All in all, today's export markets are a far cry from the glory days of 1982 when Canada exported 784 Bcf at \$4.94 per Mcf and received 3.87 billion (\$U.S.) in revenue. Nevertheless, it will be the export market that offers the major potential for expansion of the Canadian gas industry. Domestic demand for gas is anticipated to exhibit fairly stable growth over the next 10 to 15 years. U.S. demand is likely to remain fairly flat over time, but ever increasing supply costs and the gradual decline in the U.S. reserves base will create a gap between domestic supply and demand which, it is expected, will be bridged by additional gas imports.

Figure 5.1
Canadian Natural Gas Sales Revenues



SOURCE: Canadian Gas Association, 1965–1985 Historical Statistics.

This chapter provides a perspective on natural gas trade within North America. The first section examines past Canadian trade with the U.S. and the various regulations that have been in place over time. We also briefly discuss Mexican and Algerian gas exports to the U.S. The next section discusses recent trends in the export market, current market barriers, and the impacts that regulatory changes and a possible Free Trade Agreement might have on natural gas trade in the short and long term. The final section examines the potential shortfall in U.S. gas requirements and the implications this holds for future Canadian exports. Estimates of export potential formulated by GRI and other organizations are provided to illustrate the inherent uncertainty in such analyses. Finally, the issues raised by these forecasts are briefly examined. Such issues include future pipeline expansion plans, the ability of Canadian reserves to meet future deliverability requirements, and the timing of Canadian frontier production.

5.1 Historical Overview

Canadian policy towards natural gas exports has come full circle from the policies that were in place prior to 1975. In earlier years, prices were negotiated between U.S. buyers and Canadian sellers and differed depending on the point of importation and market factors. The National Energy Board (NEB) in Canada and the Federal Power Commission (FPC) in the U.S. were responsible for monitoring export/import matters to ensure that public interests were adequately protected. The NEB had its first set of export hearings in 1960 when it approved export licenses totalling 7 Tcf over a 25-year period. Initially it discharged its responsibilities through the application of a surplus rule which required that established reserves and "trend gas" (new discoveries) be sufficient to meet Canadian requirements for 30 years. The NEB subsequently revised this approach in 1966, adopting a 25A4 rule whereby Canadian needs had to be satisfied by reserves totalling 25 times requirements estimated in the fourth year of the export contract being considered. These policies were in fact more lenient than those applied by the Alberta Energy Resources Conservation Board, which monitored removal of gas from the province of Alberta.[2] The FPC generally discharged its duties by monitoring imports to ensure that prices were fair and that the gas was needed by U.S. consumers.

In monitoring export prices, the NEB was satisfied if prices met three guidelines which the Board established in 1967. The guidelines were:

(1) the export price shall cover all relevant costs including a fair rate of return on capital investment;

(2) the export price shall be fair in relation to prices charged Canadian customers in areas adjacent to point of export; and

(3) the price for export buyers shall not be appreciably less than those of alternative fuel sources.

However, in the early 1970s the two major producing provinces, Alberta and British Columbia, and the Federal Government had developed concerns about the low level of wellhead prices. Low prices were due to a number of factors, most notably the market structure of the day--there were only a limited number of out-of-province purchasers (mainly TransCanada Pipelines Limited (TCPL) and Alberta and Southern)--and the low regulated prices in the U.S. which had a dampening effect on negotiated export prices. As well, many of the long-term export contracts signed in the 1950s had little or no inflation escalation provisions built into them.

At the same time, there were concerns about future gas supplies. Rapid domestic demand growth, much greater than the NEB had anticipated, suggested an underestimate in the Board's forecast of future requirements. The Board had also revised downward its estimate of future supply capabilities from 4.2 Tcf in 1990, as estimated in 1969, to 2.3 Tcf in 1990, as estimated in 1975.[3]

In expressing its concern over export prices, the Federal Government instructed the NEB in 1970 to monitor export prices and to notify the Cabinet when significant increases in the price of competing fuels occurred in export markets. The Government of Alberta instructed the AERCB in 1972 to conduct an inquiry into the field pricing of gas in Alberta. In 1973, the new New Democratic Party government in B.C. created the B.C. Energy Commission to review energy prices. Both of these organizations concluded that natural gas prices were too low. In 1973, after the sharp increase in world oil prices, the AERCB froze removals from the province at then current levels to force TCPL to renegotiate its long-term contracts with its producers. A month later, TCPL offered a uniform price of $0.26 per Mcf to all of its contracted suppliers. Prices were to increase by $0.01 per Mcf for the next 2 years and be renegotiated in 1975.[3] In the fall of 1974, the Federal Government, in conjunction with the Alberta and B.C. Governments, instructed the NEB to unilaterally increase export prices to $1.00 per Mcf. This price was further increased by the NEB in 1975 to an average of $1.60 per Mcf.

In response to a 1976 NEB proposal to further increase the average border price, together with differentiated border prices, the U.S. proposed the concept of a uniform border price to avoid discrimination between states. The NEB acquiesced to this request and, in 1977, adopted a substitution-value approach to setting this uniform price which linked it to the cost of crude oil imports to Eastern Canada. World oil prices subsequently increased from $16 to $32 per barrel in late 1979 due to supply disruptions from Iran related to the overthrow of the Shah. This precipitous price increase triggered equivalent increases in Canadian gas export prices. From May 1979 to April 1981, export prices increased from $2.68 (Cdn.) to $5.95 (Cdn.) per MMBtu. As world oil markets began to weaken in 1983, export prices fell from $5.95 (Cdn.) to $5.43 (Cdn.). Table 5.1 presents a history, dating back to 1975, of export prices to the U.S. Since 1977, the Canadian export price has been set in U.S. dollars acknowledging the decline in the value of the Canadian dollar.

TABLE 5.1
HISTORICAL NATURAL GAS EXPORT PRICES

Year	$Cdn./MMBtu	$U.S./MMBtu
1975	1.20	1.18
1976	1.66	1.69
1977	2.06	1.94
1978	2.46	2.16
1979	2.99	2.55
1980	5.09	4.35
1981	5.78	4.82
1982	6.09	4.94
1983	5.60	4.55
1984	5.70	4.40
1985	4.36	3.20
1986	3.43	2.47

SOURCE: National Energy Board.

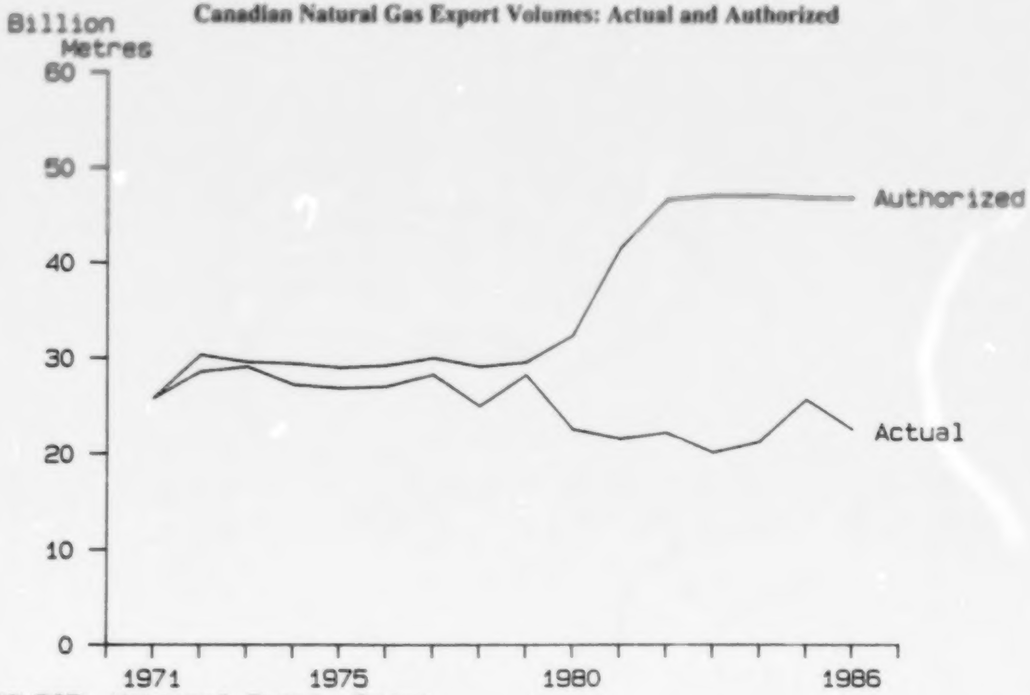
A variety of market forces were acting in concert with rising export prices to depress the U.S. appetite for Canadian gas. Through the early 1970s, wellhead price controls in the U.S. on gas destined for interstate markets had provided considerable disincentive for exploration and development of new reserves, as well as a stimulus for rapid growth in demand. Because wellhead prices in intrastate markets were deregulated, many producers were abandoning the interstate market to sell in the higher price intrastate market. These conflicting pressures resulted in rather severe curtailments in some regions between 1973 and 1976 and increased U.S. demand for Canadian gas. Faced with an impending gas shortage, the Carter administration introduced the Natural Gas Policy Act (NGPA) of 1978, a complicated phased-in plan for gas deregulation intended to eliminate the division between interstate and intrastate markets and to allow gas prices to rise to market clearing levels. The Act established 24 categories of gas production, each with its own price ceiling and agenda for deregulation. Most high cost gas was to be deregulated by November 1979, much of the rest by January 1985, but gas discovered prior to 1977 (old gas) was to be regulated until supplies were exhausted.

The atmosphere of shortage and increasing wellhead prices did much to stimulate Canadian interest in the export market. In 1978 the Federal Energy Regulatory Commission (FERC) approved large additional imports of Alberta gas as part of the western prebuild phase of the Alaska pipeline and the NEB also relaxed controls on short-term exports. The expected increase in export sales, however, never materialized. Higher wellhead prices in the U.S. had generated large increases in exploratory and, in particular, development drilling activity, increasing the productive capacity of U.S. reserves (as discussed in Chapter 3). U.S. demand had begun to falter and was particularly hard hit by the 1981-1982 economic recession. This downward pressure on demand was exacerbated by higher gas prices due to the NGPA and increasing world oil prices. As Figure 5.2 illustrates, Canadian gas export volumes began to fall after 1979. U.S. imports before 1980 had never fallen below 85 percent of authorized volumes. In 1980, export volumes fell to 70 percent of authorized volumes and in the following year declined to only 52 percent of authorized volumes.

Falling oil prices in 1983 contributed to the worsening demand situation in the U.S. as many large industrial users, who had equipped themselves with dual-fuel capacity following the gas curtailments of the 1970s, were in a position to shift very quickly from natural gas to residual fuel oil whenever gas prices began to exceed fuel oil prices. The presence of this dual-fired market effectively established a natural ceiling on gas prices to the industrial sector. Increased U.S. production was also competing with Canadian gas for a larger share of the shrinking U.S. market. As it became evident that export volumes

Figure 5.2

Canadian Natural Gas Export Volumes: Actual and Authorized



SOURCE: National Energy Board.

were not going to recover without increased price competitiveness, the Federal Government introduced the Volume Related Incentive Plan (VRIP) in the summer of 1983. Under this program, gas sold in excess of annual established base volumes could be sold for $3.40 (U.S.) per Mcf. Base volume gas, however, still sold for $4.40 (U.S.) per Mcf. Subsequently, in November the surplus rule was determined on a monthly basis. The NEB also moved to allow reductions in minimum take-or-pay provisions in export contracts.[4]

Canadian exports suffered another setback in 1984 with the issuance of FERC Order No. 380, effectively preventing U.S. pipelines from rolling in take-or-pay costs for imported gas into their rate base. Since take-or-pay penalties were still binding for gas obtained from U.S. sources, this provided U.S. purchasers with a further incentive to shift away from Canadian sources. Another factor impacting on Canadian exports was the emergence of the U.S. spot market. Transactions in the U.S. spot market for natural gas, which had been virtually non-existent prior to 1980, had increased until, in 1985, about 24 percent of gas consumed was being purchased in spot markets. It had become evident by this point that for Canadians to compete effectively in U.S. markets, increased flexibility in pricing provisions and terms of contract was required.

Market forces had begun to dictate new realities and, in November 1984, the Federal Government responded by allowing producers the choice of continuing under the VRIP program or negotiating prices directly with U.S. purchasers, subject to NEB approval. Most exporters chose the latter option. Conditions attached to these renegotiations included the Toronto City-Gate Price serving as a price floor, export prices having to be equal to or greater than the price of competing fuels in the relevant export market, and the price having to be sufficient to recover all fixed costs incurred in transporting the gas to the U.S. border.[5] As evidenced by the similarity that these conditions bore to those attached to exports by the NEB in 1967, Canadian policy towards exports had come full circle. Market sensitive pricing had emerged once more.

5.1.1 Mexican and Algerian Exports to the U.S.

Although Canada is the main exporter of gas to the U.S., Mexico and Algeria have also supplied a small portion of total U.S. demand.

Table 5.2 compares volumes of imports from these three sources. Imports from Mexico and Algeria have fluctuated far more than those from Canada. This is primarily due to the inflexible pricing policies that both the Mexican and Algerian Governments have maintained towards natural gas exports.

Imports from Mexico began in 1952, reaching about 50 Bcf annually in 1970 and by 1982, nearly 100 Bcf annually. During four years in the late 1970s, no gas was imported from Mexico due primarily to the inability of the two countries to agree upon an acceptable price. In 1977, PEMEX and a consortium of U.S. pipelines (the Border Gas Consortium) agreed upon an export price of $2.60 (U.S.) per Mcf. However, since this price was greater than the price of both Canadian imports and average U.S. gas supplies, the Carter administration refused approval of the Border Gas Contract.

In 1979 the Border Gas Consortium and PEMEX re-entered negotiations to secure a gas purchase contract. The agreed upon price was $3.265 per million Btu, to be escalated with reference to the unweighted average price of five crude oils. This revised plan was approved in 1980 and exports under the Border Gas Contract began to flow in January of that year. With the increase in Canadian gas prices to $4.47 (U.S.) per million Btu in February of that year, PEMEX applied for an increase in the price of Mexican gas to the same level. The escalator was also revised to yield parity with the Canadian gas export border price or the previous escalator, whichever was greater. When Canadian export prices declined in April 1983 from $4.94 (U.S.) to $4.40 (U.S.) per million Btu, PEMEX reduced its price to the same level in the following month.[6]

Falling gas prices over the last 4 years have caused PEMEX to re-examine its export policies. Their reluctance to lower export prices to competitive levels resulted in a decline in export volumes from 105 Bcf in 1982 to 51 Bcf in 1984. In December 1984, PEMEX and the Border Gas Consortium jointly agreed to suspend further export sales until agreement on a mutually acceptable export price could be reached. PEMEX also announced a policy under which the domestic consumption of natural gas would increase to replace residual fuel oil. Oil backed out by natural gas would then be available for sale on the international market. Since the agreement there have been no export sales of natural gas from Mexico to the U.S. Sharply increased domestic consumption and indications of falling deliverability due to lower

TABLE 5.2

U.S. NATURAL GAS IMPORTS

(volume in billion cubic feet; average price in $/Mcf)

Year	Canada		Mexico		Algeria	
	Volume	Price	Volume	Price	Volume	Price
1977	996.7	1.99	2.4	2.25	11.3	0.92
1978	881.2	2.19	0.0	0.00	84.6	1.53
1979	1000.8	2.61	0.0	0.00	252.6	3.03
1980	796.5	4.32	102.4	4.41	85.9	3.77
1981	762.1	4.83	105.9	5.01	36.8	5.54
1982	783.4	4.98	94.8	5.02	55.1	5.82
1983	711.9	4.49	75.4	4.70	131.1	6.41
1984	755.3	4.01	51.5	4.49	36.2	4.90
1985	926.1	3.17	0.0	0.00	23.7	4.60

SOURCE: United States, Department of Energy, Energy Information Administration, Natural Gas Monthly, May 1986.

discovery rates have made the resumption of Mexican exports unlikely, especially in the short term.[7]

During the late 1960s and early 1970s a number of U.S. companies introduced plans to import liquified natural gas (LNG) from Indonesia and Algeria in response to projected declines in U.S. gas supplies. Regular LNG imports commenced in 1971 with an authorization to import 15.4 trillion Btu annually from Algeria, primarily for winter peaking purposes in New England, New York, and New Jersey. In 1978, a project to import approximately one Bcf per day of Algerian LNG for use in the Mid-Atlantic and Southeastern states was proposed. However, in April 1980, this project was effectively terminated when the parties failed to agree on price changes proposed by Sonatrach, the Algerian exporter. Several other LNG import proposals were terminated either by the Economic Regulatory Administration (ERA) after it found that pricing methods were unacceptable, or by environmental opposition to the projects.

In December 1983 Panhandle Eastern Corp., the largest importer of Algerian gas, suspended LNG purchases for an indefinite period because of high prices. Currently, only small volumes of LNG exports are being purchased. Although contract negotiation between U.S. importers and foreign sellers continues, the high price of LNG imports will likely preclude any increase in volumes in the near term. Sonatrach, however, has indicated a willingness to compete more realistically in the U.S. market. In a recently concluded arrangement with Panhandle Eastern Corp., Sonatrach agreed to supply up to 3 Tcf of LNG over the next 20 years. Panhandle does not have an obligation to purchase any of the product and will not do so if market prices are insufficient to recover all costs incurred for production, liquefaction, ocean transport, and regasification.[8]

Total free world reserves of natural gas were estimated at 1938 Tcf in 1986 and many large discoveries have been made in recent years. An example is Qatar's North Field which has proved reserves of 148 Tcfs and potential resources of 378 Tcfs.[9] Given these large reserves and fairly limited world natural gas demand, a willingness on the part of LNG exporters to recognize market conditions in future contracts could provide a brake on future price increases in the U.S. and a significant source of competition to Canadian gas in the Northeast U.S. markets.

5.2 The Current Export Market

5.2.1 Recent Trends

The year 1986 was one of harsh realization for Canadian natural gas exporters. Export volumes declined 20 percent in 1986 to 740 Bcf compared with 923 Bcf in 1985, despite a 23 percent drop in export prices from $3.19 (U.S.) to $2.47 (U.S.) per MMBtu. The price and volume decreases combined to reduce total export sales revenue by 37 percent, from $4.025 (Cdn.) billion in 1985 to $2.839 (Cdn.) billion in 1986. A noticeable shift in the volume of short-term export sales relative to long-term sales also characterized the 1986 export year. Short-term sales volume increased from 16.1 Bcf in 1985, about 1.7 percent of total sales, to 201.7 Bcf in 1986 or 27 percent of total sales. Short-term gas export prices fell from $2.70 (U.S.) per million Btu in 1985 to $2.23 (U.S.) per million Btu in 1986. Long-term export prices declined similarly, from $3.20 (U.S.) to $2.56 (U.S.) per million Btu. Export volumes have recovered somewhat in 1987, increasing 20 percent from 764.7 to 920 Bcf over the contract year (November to October), but prices have continued to fall--by about 25 percent from $2.66 (U.S.) to $2.00 (U.S.) per MMBtu over the same period.

While there is no simple explanation for the slump in gas exports in 1986, two key forces played a major role in weakening the competitive position of Canadian gas in the U.S. market. First, the tumble in oil prices from about $30 (U.S.) to $11 (U.S.) per barrel during the first few months of 1986 necessitated a downward adjustment in gas prices in the industrial sector to maintain the competitiveness of gas relative to fuel oil. Despite these price declines, natural gas lost a considerable share of its market to dual-fired industrial users.[10]

Second, there continues to be a tremendous amount of excess productive capacity in the U.S. The presence of this surplus has resulted in a significant increase in gas-on-gas competition. The increasing importance of the U.S. spot market is a direct result of this type of competition, as those producers having surplus capacity and cash flow needs compete with one another to supply short-term sales. Cheap gas on the spot market has also caused U.S. buyers to reduce purchases of higher priced system gas to take advantage of potential savings. This in turn has placed interstate pipeline companies in a position where, due to regulation involving take-or-pay obligations, it is preferable for them to take domestic gas before Canadian gas secured under long-term contracts. As noted above, however, Canadian gas has picked up a growing share of the short-term, spot gas market.

5.2.2 Recent Changes in the Canadian and U.S. Gas Trade Environment

Canadian gas export sales declined in 1986 despite initiatives taken by both countries to "free up" the gas industry and increase competition at both the wellhead and the burner-tip. With regard to export sales, effective November 1, 1985 the NEB was given authority to approve, by order, gas export contracts with terms of up to 24 months. No volume limitations were applied to these short-term exports. At the same time, five conditions were imposed for approval of licensed gas exports:

- export prices had to recover their appropriate share of costs incurred;
- export prices could not be less than the price charged to Canadian consumers in the area adjacent to the point of export;
- provisions must be contained in export contracts to allow for adjustment to changing market conditions;
- reasonable assurance that contracted volumes will be taken must be provided by exporters; and
- exporters must obtain producer approval for contract changes and for new contracts.

These were in fact five of the seven criteria announced in the 1984 gas export pricing policy. The November 1985 ruling eliminated the presence of a single floor price (which previously had been the Toronto City Gate Price), and replaced it with the border price text under which gas export prices could not fall below the price in the adjacent region. It also eliminated the need for exporters to demonstrate that the economic return to Canada would be enhanced by new contract terms. In October 1986, the Federal Minister of Energy, Mines and Resources, The Honourable Marcel Masse, replaced the border price test for gas exports with a price monitoring process. Under this process, export prices are monitored to ensure that they do not remain below prices paid by Canadians over sustained periods.[11]

This provision was part of an agreement between the Federal Government and producing provinces which also called for a review of the NEB 15-year gas surplus test. The NEB has completed this review and released its decision in July 1987.[12] The new surplus determination procedure is a distinct departure from previous procedures in that it does not employ a formula to determine whether a proposed export is surplus to reasonably foreseeable Canadian requirements. Instead, as "it would now be anomalous and contrary to free market operation if the level of gas supply to Canadians were to be determined by other than market forces,"[13] the Board has moved to a "Market Based Procedure."

Under this procedure, the Board will carry out its mandate to ensure that natural gas licensed for export is surplus to reasonably foreseeable Canadian requirements through a two-pronged process. The first check will be by monitoring Canadian energy markets on an ongoing basis through the Board's traditional biannual assessment of Canadian energy supply and demand. In addition, the Board will periodically publish reports analyzing short-term natural gas supply, demand, and pricing trends.

The second aspect of the new procedure will be a public hearing process on export proposals for terms greater than 2 years. During these hearings the Board assessment of the merits of the export proposal will consist of three main components:

- a Complaints Procedure, under which domestic natural gas consumers can object to the export proposal if they have found that they cannot contract for additional supplies of gas under similar terms to the export proposal;
- an Export Impact Assessment, which requires license applicants to submit an analysis of the impact the proposed export will have on future Canadian natural gas demand and supply, and also prices; and
- a Public Interest Determination, to ensure that all other relevant factors are considered in determining if the export proposal is in the public interest.

As noted in Chapter 2, the new procedure is unlikely to have any impact on exports in the short term because of the current surplus in domestic gas supplies. In the longer term, however, it is likely to have serious implications for future natural gas price formation in Canada. A key provision in the public hearing component of the new order is that,

> ... gas should not be authorized for export if Canadian users have not had an opportunity to buy gas for their needs on terms and conditions similar to those of the proposed export.[14]

Thus, prices in Canada will in the long term largely be determined by the price of gas in the United States which will in turn depend on the prevailing and expected demand/supply situation in the U.S. as well as an alternative fuel prices. However, rising prices in the U.S. will not necessarily imply equally high prices in Canada if, at the same time, export volumes and domestic demand have not increased sufficiently to diminish the current deliverability surplus in domestic gas production. Nevertheless, the new surplus rule in combination with market sensitive pricing for Canadian exports has laid the ground-work for the formation of a unified North American or continental gas market.

Even though gas producers strongly favour the new surplus rule, some concern has been expressed about various aspects of the ruling. In particular, whereas under the previous surplus test producers could be reasonably certain that proposed exports would be approved given the existence of a public formula, now every large export proposal will likely go to the NEB under the complaints procedures and the outcome may have strong political overtones.

Canadian gas producers are now in a position to respond effectively to changes in export market conditions. No longer is the export price mandated by government policy. Instead, it will be determined through negotiation between buyers and sellers. Canadian exporters will also be able to freely negotiate the term of the contract and no formal volume restrictions will be applied to proposed exports. With the intense competition present in the U.S. market, these kinds of provisions are necessary to allow Canadian producers to remain competitive with their U.S. counterparts.

It is the responsibility of the Economic Regulatory Administration (ERA) to authorize all imports of natural gas into the U.S. The ERA must approve an application to import gas unless it is determined that the import is not consistent with the public interest. This determination is based on a number of considerations, including:

- it competitiveness of the import. The contract arrangement must be sufficiently flexible to permit pricing and volume adjustments as required by market conditions and available competing fuels including domestic produced gas;

- the need for the natural gas. This is addressed in terms of the marketability of the proposed imports; and
- security of supply. An import is deemed secure if it does not lead to undue dependence on unreliable sources of supply. Longer-term imports must demonstrate relatively greater reliability of supply than short-term imports.

Canadian exporters are in a position to readily meet all of the above requirements.

The FERC is responsible for regulating issues pertaining to the siting, construction and operation of pipeline facilities, the rates charged for interstate transportation and sale of natural gas, as well as domestic wellhead prices. Since Canadian gas reaches U.S. consumers through the same transportation systems that deliver domestically produced gas, the FERC maintains the above regulatory responsibilities for imported gas.

The goal of the present administration is to have a deregulated market under which the actions of buyers and sellers are dictated, to as great an extent as possible, by market forces free of regulatory encumberances. To achieve this goal, the FERC and the U.S. Department of Energy have issued a number of orders and policy directives designed to allow market forces to operate as freely as possible, as discussed in Chapter 2. The full effect of these initiatives has yet to be felt in the export market because of numerous difficulties arising in their implementation. The sheer complexity of the rulemakings and the issues that are arising in their wake forbid a detailed discussion. We will, however, discuss the main thrust of these attempts as they relate to current and future trade in natural gas between Canada and the U.S.

As noted in Chapter 2, recent U.S. regulatory policy has focussed on two primary issues:

- removing the market distortions created by the remaining cushion of old gas being sold at prices below market clearing levels; and
- opening up the transportation system to allow consumers access to least cost alternative gas supplies, and producers the opportunity to sell their gas at market clearing prices.

The FERC has released two orders addressing these concerns. The first, FERC Order No. 451, was released in May 1986 and addresses the first issue. Under the order, the multi-tiered vintage based pricing of old gas as defined by the NPGA is eliminated and a uniform alternative ceiling price equal to the NGPA Section 109 Maximum Lawful Price (MLP) of $2.126 (U.S.) per MMBtu (April 1987) is established. Because of the alternative nature of the ceiling price, producers are not entitled to collect the price without either voluntary negotiations or the mandatory "good faith negotiation" procedure (GFN). Under GFN, once a producer initiates upward price renegotiation of any old gas, the pipeline may initiate downward price renegotiation of any new gas covered by contracts that also cover old gas. If such negotiations fail, either the producer or purchaser can terminate the contract.

The U.S. Department of Energy has estimated that full decontrol of old gas could result in the addition of 24 to 44 Tcf of old gas reserves to the resource base. Higher wellhead prices would provide greater incentives for producers to increase old gas production through three production methods:

- Delayed Abandonment--Since producers abandon a well when revenue generated from its operation no longer covers operating costs, increased prices will allow continued operation of a well and ultimately, greater gas production.
- Infill Drilling--Infill wells increase recovery from known reservoirs in existing fields by drilling at closer spacing than originally planned. Higher prices will provide stimulus for such activity.
- Well Stimulation Techniques--Production rates and ultimate recovery of old gas can be increased through the use of such technologies as hydrofracturing, reperforation, acidization and water disposal operations. Higher prices will encourage producers to re-evaluate the economics of such techniques.[15]

The impact that FERC Order No. 451 or other efforts to decontrol old gas will have on Canadian exports is not clear. Little activity has resulted from the order to this point, due to the depressed level of wellhead prices and current surpluses. When the current gas bubble ends, however, producers will be able to realistically command the new MLP without as much worry about lost revenue from renegotiated contracts covering new gas. It is likely that this will provide some upward pressure on the overall rolled-in cost of U.S. gas.

While any increase in export prices would be welcomed by Canadian exporters, such increases will also result in increased competition from incremental old gas produced as a result of such price increases. Under new export policies now in place in Canada, Canadian exporters should be able to respond to such changes in an optimal fashion, if certain other obstacles in the U.S. gas market are also removed.

Access to pipeline transportation is the most important of these obstacles facing Canadian exporters. The issue of transportation availability has emerged as the most controversial and, perhaps, most critical of the current deregulation initiatives in the U.S. However, the FERC's attempts to implement an open access transportation network, first through Order No. 436 and now through Order No. 500, have met with considerable resistance from all sectors of the gas industry. The acceptable resolution of the interstate pipelines take-or-pay situation forms the core of this resistance (as discussed in Chapter 2). As a result, only a limited number of interstate pipelines have opted to apply for open-access status under Order Nos. 436 and 500. Those pipelines that have not implemented open access transportation can still provide transportation service through grandfathered transportation agreements or by obtaining individual Section 7(c) certificates.

Competitive pressure should ultimately limit the widespread use of Section 7(c) certificates for transportation. Because of the recent ban by FERC on flexible receipt and delivery points, any pipeline wishing to move large volumes of transportation gas will need to file a number of certificates and find itself faced with a $15,000 cost for each certificate filed. Additionally, the certificates must be approved before the transportation of third-party gas can begin. In contrast, an open-access transporter with blanket certification under Order No. 436 can implement non-discriminatory transportation arrangements at any time.

Under a workable, widely accepted open access program, it will become much easier for producers and end-users to negotiate directly for natural gas sales. This should, in the short term, increase the relative importance of the spot market, as those producers with shut-in gas or excess deliverability will be able to market this gas at market clearing prices and experience less difficulty in obtaining the transportation service required to deliver it to end-users. For Canadian producers, open access transportation, as envisioned under Orders No. 436 and 500, will improve their ability to access all segments of the U.S. consumption sector as U.S. pipelines will be required to provide non-discriminatory transportation for Canadian gas. Canadian exporters could then deal directly with U.S. end-users such as large industrial users, electricity generating plants, or local distribution companies rather than with the interstate pipeline companies. However, Canadian gas will have to compete directly with U.S. gas for these sales. If the U.S. pipeline is not an open access carrier, it is under no such obligation to carry Canadian gas.

While the productive capacity surplus persists in the U.S., activity on the spot market will continue to be vigorous. Since most producers are reluctant to enter into long-term sales agreements at the low level of current prices, most sales are likely to be short-term until prices begin to firm. Canadians will thus have to compete on a price basis for the near term. As U.S. supplies begin to dissipate, the spot market is likely to diminish in importance and long-term contracts will regain a larger share of the market. Security of supply will then become an important factor in the negotiation process and U.S. end-users may choose to return to purchasing system gas from the interstate pipelines or enter into their own long-term contracts. If this situation develops, takes of Canadian gas volumes still under contract could be expected to increase. Open access to U.S. pipelines would improve the ability of Canadian exporters to meet the unique requirements of those end users not opting to return to system supplies.

A second aspect of U.S. pipeline regulation that impacts on Canadian export sales is the decision by the FERC to move to a zoned rate structure. This decision, although it is in accordance with the Order No. 436 call for distance-related transportation rates, has essentially conferred a delivered price advantage to U.S. produced gas over Canadian gas. The large toll zones established by the FERC require that Canadian exporters moving gas a short distance from the border pay nearly the same transportation rate as U.S. producers moving gas from as far as Texas.[16]

With respect to other regulatory developments, the FERC recently issued Opinion 256 forbidding Canadian pipeline demand charges, that were negotiated during the restructuring of certain export contracts in 1984, from being passed through on an "as-billed" basis in the calculation of U.S. pipeline charges. Essentially, the opinion was rendered because of differences in the manner in which pipeline tariffs are regulated in the two countries. Canadian pipeline tariffs are determined using the full fixed variable rate design which requires that most pipeline fixed costs be recovered in the demand portion of the tariff. In the U.S., a modified fixed variable rate design is employed which loads return on equity and taxes into the commodity portion of the tariff. As a result, U.S. pipelines carrying domestic gas find their commodity charge higher than those pipelines carrying Canadian gas. In addition, the cost to the pipeline of accessing an additional Mcf of contracted gas tended to be lower from Canadian sources than from U.S. sources because of the lower commodity charge for otherwise equivalently priced gas supply. FERC felt that this conferred to the latter pipelines a competitive advantage and issued the opinion to "level the playing field."

Canadian gas producers and politicians protested the decision, arguing that the new rules could cost producers anywhere from $140 million to $400 million a year in lost sales and that the Commission was extending its jurisdiction to Canada.[17] In May 1987 FERC recognized the change in the rate structure used by NOVA for its transmission customers and allowed partial pass-through of NOVA demand charges. NOVA had changed from a postage stamp rate to a two-part demand-commodity structure in November 1986, and the Commission had not considered the change in their December meeting. Also in May, TCPL, Westcoast, and ProGas filed requests for a review of FERC's decision with the U.S. Court of Appeals for the District of Columbia.

It is not an easy task to assess the impact that this ruling will have on Canadian exporters. Since the ruling only applies to firm transportation sales, interruptible or short-term sales are exempt (interruptible transportation rates do not have a demand charge component in their rate structure). Furthermore, as discussed above, in an open access environment Canadian exporters will increasingly sell gas directly to U.S. end-users, utilising interstate pipelines for transportation only. Under this type of agreement, fixed costs are recovered directly from the purchaser, thus bypassing the effect of Opinion 256 completely.

5.2.2.1 The Free Trade Agreement

Decisions by Canadian authorities to allow market determined export prices and to remove the export surplus rule in combination with U.S. efforts to deregulate the gas industry on its side of the border, have engendered considerable momentum for the creation of a continental gas market. The recent Free Trade Agreement between Canada and the U.S., if ratified, will reinforce this movement to a single North

American gas market. The essential elements of the Agreement as it relates to natural gas trade are that both sides have agreed to prohibit restrictions on imports or exports, including quantitative restrictions, taxes and minimum import or export prices, or any other equivalent measure.

A key exception to these provisions is that if the resource is declared to be in short supply, the exporting party may impose quantitative restrictions for conservation purposes. However, the exporting party must provide the importing party proportional access to that supply without discriminating on price. The agreement also grandfathers existing regulations that may be in conflict with the spirit of the agreement, such as Opinion 256. Future regulatory actions that might be discriminatory towards either country will be dealt with in non-binding consultations between the two governments.

With regard to cross-country investment, declared policies and practices are grandfathered. In particular, this refers to Canadian policies forbidding foreign takeover of financially healthy Canadian energy companies. "More specifically, the Agreement binds the Parties not to adopt policies requiring minimum levels of equity holdings by their nationals in domestic firms controlled by investors of the other Party, or requiring forced divestiture."[18]

The Free Trade Agreement will have little if any impact on gas markets in the short term, but its long-term impact is potentially significant. The movement to a continental or North American gas market implies that, first, Canadian export volumes will be determined by the competitiveness of Canadian gas relative to U.S. gas in the U.S. market. And second, that Canadian prices will be heavily influenced by the price these exports receive in the U.S. market. Given that supplies in the U.S. can be expected to tighten considerably in the future, gas producers could expect increasing export volumes at increasing prices. Canadian consumers will then have to compete with U.S. purchasers for their gas supply.

Perhaps the greatest long-term concern evident in the Free Trade Agreement is the provision providing the U.S. proportional access to Canadian gas if at some point in the future the Canadian government wishes to place quantitative restrictions on exports. It is not yet clear whether or not this means proportional access to production at the time the resource is declared in short supply, or if it means production plus future increments in supply. For example, consider situation in which annual Canadian production is 3 Tcf and 1 Tcf is being exported to the U.S. In the former case, this would imply that the U.S. had the right to purchase 33 percent of any production from those reserves in place at the time restrictions are imposed. They would not have any call on reserves added after that point. Thus the portion of production being exported would decline over time. In the latter case, the U.S. would have the right to one third of Canadian production for an indefinite period. If Canadian gas production were to decline over time, this would result in some portion of the Canadian market having no choice but to revert to alternative fuels.[19]

Clearly, the implications which the Free Trade Agreement holds for future gas trade are not yet adequately understood, nor are certain provisions adequately defined as illustrated above. But, it must be remembered that the energy component of the Free Trade Agreement follows the spirit of recent regulatory changes in the Canadian and U.S. gas industry. These changes have already evinced considerable momentum in moving Canada-U.S. gas trade towards a continental market. The failure of the Free Trade Agreement to become reality would do little to slow this momentum.

5.3 Export Market Outlook: A Survey of Different Views

Uncertainty regarding the magnitude and duration of the current U.S. gas bubble, future alternative fuel prices and gas demand, the future productive capacity of Canada's Western Sedimentary Basin, and the cost of Canadian frontier supplies, all combine to make the forecasting of future export volumes a most difficult exercise. In order to prepare an export market forecast, the following variables must be assessed:

- U.S. natural gas demand;
- U.S. natural gas productive capacity;
- alternative import supplies from Mexico and Algeria; and
- Canadian natural gas demand and supply.

U.S. demand is compared to domestic supply over the time horizon of the forecast and the resulting imbalance is roughly considered to be the U.S. demand for imported gas. The ability of import suppliers to meet this demand is then evaluated and, if an imbalance persists, U.S. demand and supply are re-evaluated at a different price track. The process continues until U.S. demand and supply are roughly equated.

Obviously the process is more difficult than outlined above. Numerous potential developments in both end-use and supply technologies must be accounted for on a sectoral basis and on a regional basis. Technical progress in the supply and use of other energy forms must be taken into account as such changes also impact on future natural gas demand. Because of the nature of competition between gas and alternative fuels in the various sectors (mainly gas and residual fuel oil in the industrial sector), a forecast of alternative fuel prices is generally used to determine the level of future natural gas prices and hence demand.

The derived price for natural gas is then used to project natural gas deliverability over time. A standard methodology used to estimate future deliverability is to use the price level to project drilling activity over time. The estimate of drilling activity is then used to estimate future reserves additions and standard assumptions regarding production are used to produce an estimate of deliverability. This estimate of deliverability is then combined with the gas demand forecast to arrive at either the future supplies that will be required in the U.S. or the future capability of Canada to export gas.

This type of approach, however, can lead to some serious problems and obscure important regional trends. First, the cost of finding and developing new reserves of natural gas is a critical variable in the analytic process. Future drilling activity will be a function of the difference between this cost and the price received by producers (net of taxes and royalties). Because resource costs will increase as the resource base is depleted, the pressure this places on producer profit margins must be accounted for in assessing future drilling activity.

Second, if natural gas prices are forecast as a function of forecast alternative fuel prices, gas prices are essentially decoupled from the underlying supply situation. This can lead, in the case of low oil prices, to increasing gas demand because of lower gas prices and, eventually, a gap between demand and supply because of the inability or unwillingness of producers to meet that demand. In a reasonably competitive market, demand and supply must roughly balance over time and prices will rise causing additional supplies to be available and some portion of the market to switch to alternative fuels. The forecast of gas prices and demand is thus fundamentally incorrect and caused by the fact that gas prices are "hardwired" into the analytic process rather than calculated explicitly as the combined interaction between gas demand, supply and alternative fuel prices.

Finally, important regional trends can be obscured if demand and supply are not treated on a regional basis. Relative resource costs in different supply regions and the existing pipeline infrastructure will interact with regional demands to determine the future flows of natural gas. This is particularly important for gas trade issues such as the planning of future pipeline expansion or construction which requires accurate estimates of export flows, in terms of both volume and destination. It should be stressed that these are not implied criticisms about the methodologies underlying the import forecasts described below. Rather, they are provided as cautionary advice to consider when assessing the validity of any particular forecast of natural gas demand and supply.

In order to provide a benchmark or reference point for our outlook on the future export market, and to illustrate the inherent uncertainty of such forecasts, we have provided the following survey of export market forecasts. As Table 5.3 illustrates, there is a tremendous diversity of opinion with respect to future export volumes. These differences arise for a number of reasons including different modelling procedures, slightly different oil price forecasts and different perceptions about future gas resources.

The NEB feels that the future productive capacity of Canadian natural gas reserves will seriously constrain exports beyond 1995. This is a result of their pessimism regarding future reserves additions in the Western Sedimentary Basin and the feasibility of Canada's frontier resources. Their approach is different from the others in that they make no explicit attempt to analyze the U.S. demand and supply outlook.

The other forecasts generally concur that the U.S. will require significant import volumes in the future and that Canadian gas resources are sufficient to meet this demand. Differences arise, however, in the timing of these volumes. The ARC, AGA, DRI, CERI-Pace, and WEFA Group feel that there is considerable potential in the near term as indicated in their projected exports for 1990 and 1995. GRI, on the other hand, feels that U.S. supplies will be sufficient to dampen Canadian import requirements to 1200 Bcf in 1995. They subsequently project U.S. demand for Canadian gas to increase quite rapidly to 2300 Bcf in the year 2000 and 2400 Bcf in the year 2010.

TABLE 5.3

VARIOUS FORECASTS OF CANADIAN NATURAL GAS EXPORTS TO THE U.S.

(billion cubic feet)

Year	Alberta Research Council[a] (ARC)	Data Resources of Canada[b] (DRI)	WEFA Group[c]	NEB[d]	AGA[e]	GRI[f]	CERI Ltd./ Pace[g]
1990	2000	1300	1450	1330	1400–2000	1000	1400
1995	2190	1800	1960	1476		1200	1800
2000	2030	1636	2290	637	1400–2000	2100	1800
2005	1700	1364	2010	132		2000	NA
2010	NA	NA	NA	NA	1400–2000	2400	NA

[a] Alberta Research Council, The Alberta Natural Gas Trade Model, 1987.

[b] J. A. Osten, "Trading Energy For Growth and Profit," paper presented at Energy Options: A Canadian Dialogue, June 15-16, 1987.

[c] The WEFA Group (formerly Wharton Econometrics), North American Natural Gas Study Volume 1: Crisis in the Marketplace: Estimates of Supply and Demand, 1987.

[d] The NEB does not explicity forecast natural gas exports. The above projections are calculated as the difference between productive capacity and primary natural gas demand for the high oil price case in Canadian Energy Supply and Demand: 1985-2005. The Board did, however, project export levels for 1990 in this publication.

[e] American Gas Association, The Gas Energy Supply Outlook Through 2010, October 1985.

[f] Gas Research Institute, 1985 GRI Baseline Projection of U. S. Energy Supply and Demand to 2010, 1986.

[g] CERI Energy Research Ltd. and the Pace Consultants Inc., Natural Gas Industry Service: Annual Report, December 1986.

As we will be employing the GRI demand projections in our outlook for the export market, we provide in Table 5.4 a more detailed breakdown of their supply/demand balance for the U.S., and their projections of import sourcing and volumes.

The GRI's projection of low Canadian gas exports in 1990 is due primarily to a flat U.S. consumption trajectory between 1985 and 1990 and the persistence of the current U.S. gas bubble. If supply is available at competitive prices, GRI feels that gas consumption can grow to 19 quads or more in the 1990s and beyond, principally as a result of increased gas consumption in the commercial and electric utility sectors. U.S. natural gas production is anticipated to remain constant through 2000 because of the contribution of incremental production projected from advanced technologies. After 2000, U.S. production declines sharply despite the inclusion of 1.2 quads of North Alaskan gas to the Lower-48 market. Combined with constant gas demand through 2010, total U.S. import demand increases from 1.0 quads in 1990 to 4.0 quads in 2010.

The baseline projection shows that Canadian imports only increase 0.3 quads between 1985 and 1995. By 2000, however, Canadian imports have increased by almost 1 quad with more than half of this increase due to the availability of gas from the Canadian frontier regions (Arctic and Eastern offshore). Canadian imports remain relatively constant through 2010 with frontier gas supplying up to 1 quad of total imports due to declining conventional productive capacity.

GRI assumes that Mexican imports will not resume until after 2000 and will reach 1.0 quads by 2010. This resumption requires a substantial change in current policy by the Mexican Government and significant additional pipeline construction to expand Mexican export capacity beyond its current maximum of 100 Bcf per year. LNG imports are assumed to come from Caribbean countries such as Trinidad, Tobago and Venezuela, due to their favourable proximity to U.S. markets and large gas reserves relative to domestic consumption. Resumption of LNG imports from Algeria is considered less likely due to high landed costs that would be non-competitive in the U.S. market. LNG imports are expected to commence in 2000 at a total volume of 0.2 quads and increase through 2010 to 0.6 quads.

TABLE 5.4

1986 GRI BASELINE PROJECTIONS OF U.S. DEMAND AND SUPPLY TRENDS (quadrillion Btus)

	1985[a]	1990	2000	2010
Demand				
Industrial	7.1	7.2	7.2	6.8
Electricity Generation	3.2	2.5	3.9	3.9
Transportation	0.5	0.6	0.7	0.8
Commercial[b]	2.5	2.6	3.1	3.6
Residential[b]	4.5	4.5	4.2	3.9
Total	17.8	17.4	19.1	19.0
Supply				
Lower 48 Production[c]	15.8	15.7	15.9	13.0
Base Technology	(15.8)	(15.4)	(13.4)	(8.4)
Advanced Technology[c]	(-)	(0.3)	(2.5)	(4.6)
Alaskan Production	0.2	0.2	0.3	1.5
Southern[d]	(0.2)	(0.2)	(0.3)	(0.3)
Northern[e]	(-)	(-)	(-)	(1.2)
Coal Gas	f	f	f	0.1
Other Gas[g]	0.4	0.1	0.2	0.2
Imports	0.9	1.0	2.3	4.0
Canada	0.9	1.0	1.6	1.4
Canada Frontier	0	0	0.5	1.0
Mexico	0	0	0	1.0
LNG	f	f	0.2	0.6
Total Purchases	17.3	17.0	18.7	18.8
Losses and Plant Fuel	1.0	1.0	1.0	0.8
Total Supply	18.3	18.0	19.7	19.6
Lease and Exports	0.5	0.6	0.6	0.6

SOURCE: Gas Research Institute, 1986 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010.

[a] Taken from the February 1986 DOE/EIA Monthly Energy Review.

[b] Historical EIA statistics for 1985 do not disaggregate data for the residential and commercial sector. Data for 1985 represents an estimated disaggregation of total commercial and residential energy consumption based on the historical shares in each sector.

[c] Lower 48 production does not include lease and plant fuel supplies.

[d] Southern Alaska natural gas supplies were estimated from projected Alaskan consumption.

[e] Northern Alaska natural gas represents supplies delivered to Lower 48 via ANGTS.

[f] Less than 0.05 quad.

[g] Other gas includes SNG from petroleum, propane-air, and refinery gas. In 1985, it includes net supply from storage.

5.3.1 Issues

The capital intensive nature of the natural gas industry, particularly the development of frontier gas reserves and requisite transportation facilities and new pipeline construction or expansion, requires that industry participants have a firm grasp of long-term supply and demand trends and associated uncertainties so that the long range planning necessary for implementation of such projects can proceed in an optimal manner. Because of the engineering complexity, environmental implications, large capital costs, and risk associated with long-term supply alternatives and capacity expansion, there is an extremely long lead time between the initial planning stages and actual construction. This underlines the need for "accurate" long-term forecasts, so that such projects come on stream when they are needed, not 5 or 10 years after (or before).

The forecasts examined in this section raise a number of important issues that must be, and to some extent are being, addressed by industry and government officials. Given that Canada's current export capacity is about 1.6 Tcf per year, all forecasts except that of the NEB suggest that a considerable expansion of this capacity is necessary. The forecasts differ, however, as to the magnitude and timing of this required expansion. Furthermore, the market areas in the U.S. to which these new volumes will be flowing must be accurately identified.[20]

The productive capacity from future reserves additions in the Western Sedimentary Basin (WSB) is a key parameter in the planning equation. The timing and volumes that will be required from frontier sources, especially from the Arctic region, is dependent on the future capacity of the WSB. Numerous factors will impact on the future productivity of the WSB including the undiscovered resources in the region, the profitability of exploration and development activity, and advances in nonconventional tight gas supply technology. For the full potential of the region to be realized, producers must be free to use an undistorted market price as their decision criteria regarding future drilling investments and research funding. Given the intensity with which U.S. Lower-48 reserves have been and will continue to be developed, the WSB potential is considerable. However, it remains up to the provincial and federal governments to decide if such intensive development of the WSB would be in the general public interest.

The major remaining issue is the timing of frontier resource development. As the above discussion suggests, this will largely depend on the extent to which the WSB is developed and government policy regarding the depletion of these reserves. The two frontier regions are likely to serve distinctly different market areas, so that the timing of their development will also be determined by the demand for natural gas in these markets and the cost and availability of competing sources of gas and alternative fuels. This is particularly true for the Eastern Offshore region whose proximity to the Northeastern U.S. market, a market where substantial import requirements are anticipated due to the high delivered cost of U.S. gas and large peaking requirements in excess of current capacity, offers a significant opportunity for development of offshore reserves.

Northern gas will be competing in the same markets currently being served by gas produced from the WSB. It will thus have to compete with the various alternative supplies to which these regions have access. In order to finance the large capital requirements of these frontier projects, long-term sales agreements will have to be entered into. The premium that buyers are willing to pay for such long-term, secure supplies will be largely determined by their expectations of future supply shortages from traditional suppliers.

Footnotes

[1] Because export prices were usually higher than domestic prices, the producing provinces instituted a "flowback" system whereby additional revenue generated by export sales was shared by all producers according to their share in total provincial production. This acted to reduce the incentive for producers to exploit opportunities for export sales and, at the same time, increased the funds available for investment in additional drilling activity.

[2] The development of Canadian controls on natural gas exports is discussed in more detail in G. C. Watkins, The Development of Canadian Controls on Natural Gas Exports (Boulder, Colorado: ICEED, 1987).

[3] Canada, National Energy Board, Canadian Natural Gas: Supply and Requirements (Ottawa: Ministry of Supply and Services, 1975).

[4] See A. Plourde and M. E. MacGregor, Regulating and Deregulating Canadian Natural Gas, Energy Study No. 87-3, Institute for Policy Analysis (Toronto: University of Toronto, May 1987).

[5] In general, the restructured contracts adopted a two-part demand and commodity charge in lieu of the one-part commodity charge previously employed. The demand charges replaced take-or-pay commitments of importing pipelines and were negotiated at a level sufficient to cover the exporters fixed transportation and administration costs.

[6] A more detailed discussion of Mexico's gas trade relationship with the U. S. can be found in a study by the Royal Bank of Canada, The North American Gas Industry (Canada: Royal Bank of Canada, 1984), pp. 90-92.

[7] Conversation with U.S. Department of Energy official.

[8] Some details of this contract were reported in Natural Gas Week International, May 4, 1987, p. 1.

[9] Ibid., p. 1.

[10] The AGA estimates gas demand fell by 618 Bcfs because of fuel switching, Gas Energy Review, vol. 15, no. 9, September 1987, p. 3.

[11] Letter from the Honourable Marcel Masse, Minister of Energy, Mines and Resources to Mr. Roland Priddle, Chairman, National Energy Board, News Release, June 24, 1987.

[12] Canada, National Energy Board, Reason for Decision in the Matter of Review of Natural Gas Surplus Determination Procedures (Ottawa: Ministry of Supply and Services, July 1987)

[13] Ibid., p. 24.

[14] Ibid., p. 24.

[15] United States, Department of Energy, The Natural Gas Policy Act Amendments of 1986 (Washington: D.O.E., April 1986), pp. 37-41.

[16] For example, it costs an American producer in the Hugotan field of Kansas about \$0.58 (U.S.) per MMBtu to ship his gas 850 miles via ANR to McHenry County, Illinois. In contrast a Canadian shipper delivering gas through Emerson must pay transportation costs of \$0.46 (U.S.) per MMBtu to Great Lakes and \$0.40 (U.S.) per MMBtu to ANR to get his gas to the same point, even though the total distance is about 100 miles less than the U.S. shipper. And, although the Canadian gas is shipped less than one-quarter of the distance on ANR, the transportation cost is over two-thirds that paid by the American shipper.

[17] This estimate of the potential loss in revenue to Canadian exporters was reported in Natural Gas Marketing Report, vol. 3, no. 10, June 2, 1987, p. 3.

[18] Canada-U.S. Free Trade Agreement, Elements of the Agreement, p. 9.

[19] For example, if Canadian production declined to 2.5 Tcf, Canadian consumption would have to fall from 2 Tcf to 1.86 Tcf or about 17 percent. If Canadian gas was supplying about 5 percent of U. S. requirements, consumption would fall only by about 1 percent.

[20] Currently there are numerous proposals to expand pipeline capacity to the U.S. Most of these projects concern capacity expansion into the New England/Mid Atlantic region. The FERC has announced an "open season" beginning July 24 through Dec. 1, 1987 to reconcile the over 100 applications that have been made to supply gas service to this region and to allow new submissions. The major Canadian proposal involves the second phase of the Boundry Inc. export license. The proposal involves the expansion of TCPL facilities and the construction of the Iroquois gas pipeline to deliver Canadian gas to a consortium of U.S. LDCs.

Chapter 6

THE GRI NORTH AMERICAN REGIONAL NATURAL GAS MODEL

In order to represent the vast scope and extent of the North American natural gas industry and its potential future evolution, a comprehensive modelling framework is required that incorporates:

- a complete range of existing and potential sources of gas and where they are located;
- a complete range of existing and potential gas consumers and where they are located;
- a complete range of the existing and potential transmission facilities interconnecting the above; and
- the impact that market clearing forces will have on prices and quantities as the Canadian and U.S. gas industries evolve toward less market regulation.

This chapter of the study describes such a model that has been used by the Canadian Energy Research Institue (CERI) to assess the future prospects and development opportunities of the Canadian natural gas industry. All of the more technical material has either been relegated to Appendix G (Section G.1) or is referenced in the body of the Chapter. The discussion herein focusses on the essential ingredients of the model. Accordingly, Section 6.1 briefly describes the developmental history and important elements of the Generalized Equilibrium Modelling System (referred to as GEMS hereafter), upon which the gas model is based. Section 6.2 discusses the application of this methodology to the gas industry and, in particular, focusses on the regional structure of the model and the data inputs which are used to parameterize the demand, supply, and transmission sectors of the industry. The final section highlights those aspects of the modelling approach that make it a particularly powerful analytical tool for analyzing the future prospects of the Canadian natural gas industry within the increasingly integrated North American gas market.

6.1 The Generalized Equilibrium Modelling System

The Generalized Equilibrium Modelling System (GEMS) is a software package that has been developed by Decision Focus Inc. (DFI) to facilitate the construction of large scale economic models that consist of systems of linked submodels. The methodology of generalized equilibrium modelling originated in the construction of the SRI-Gulf synthetic fuels model developed by Cazalet and others in 1977.[1] The SRI-Gulf model is a multi-region dynamic model of United States energy markets containing submodels representing over 1000 separate energy technologies.

In 1977, the Energy Information Administration of the U.S. Department of Energy built a generalized equilibrium energy model of the U.S. to be used in long-range forecasting.[2] The GEMS software system was developed (in 1978) specifically to facilitate the construction of large-scale generalized equilibrium models. Since then, the GEMS software has been used to build more than twenty large scale economic models as well as other models for specific policy applications.[3]

The Generalized Equilibrium Modelling System consists of three principal elements:[4]

- a library of process models describing the behaviour of agents within an economy;
- a network describing the interaction among the different processes; and
- a solution algorithm for determining the numerical values of all variables in the model.

A process is defined as a model of a subsystem or sector of the overall system being modelled. For example, in the natural gas model, process submodels are used to describe the production, transmission and consumption of natural gas. A network consists of a linked set of process models and in the natural gas model, represents the spatial relationship between various demand and supply regions and the transmission facilities interconnecting them. The algorithm used to solve the model finds the set of prices and quantities that through time simultaneously satisfy all physical, behavioural and financial relations embodied in the processes and linkages as defined by the network.

Again using the natural gas model as an example, this solution results in a number of market clearing prices, each specifying the economics and quantities of natural gas for a particular location at a given point in time.[5] (Appendix G contains a more detailed description of GEMS, in particular a more in depth discussion of the above three elements of the modelling procedure.)

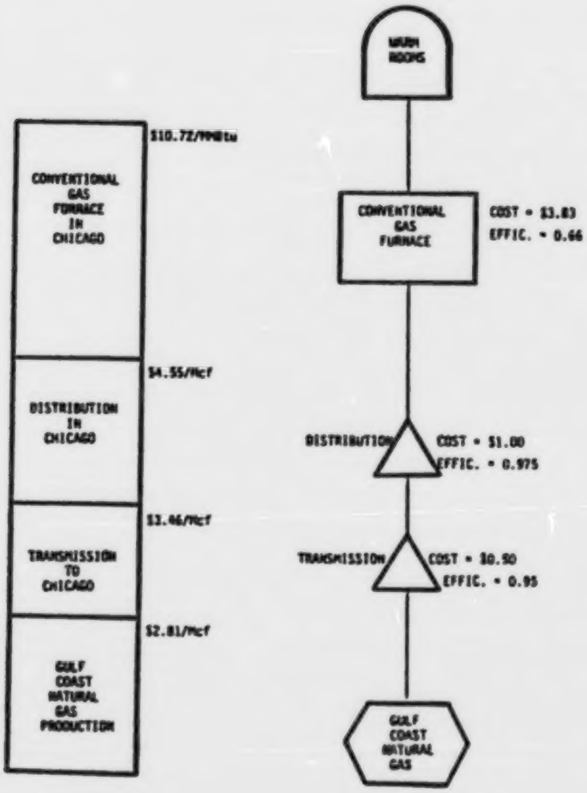
Before addressing the development and structure of the GRI Regional Natural Gas Model, it is important to communicate the GEMS conception of the energy market. One can view the energy system as being comprised of a number of chains of technologies (i.e., processes). Figure 6.1 is an example of one of the many chains in the North American natural gas industry, beginning with natural gas production on the Gulf Coast. Once produced, the gas is delivered to a long distance transmission company for transmission to the Chicago area where it is sold to a distribution company. The distribution company transports the gas to a residential consumer, who in turn consumes the gas in a conventional furnace to produce a final consumable product--warm rooms. At each stage in the chain a new, higher quality product is produced, cost is added, and thermal efficiency is lost.

One can imagine the immense number of chains that are generated once the multiplicity of supply and demand regions are accounted for and the desired level of disaggregation within each of these regions is implemented. Given this complexity, the network structure of the GEMS allows the construction of a consistent analytical framework into which these chains are input. The user must then specify the technological parameters underlying the different technologies (or processes) in the chains such as the cost and magnitude of undiscovered gas, end-use demand in the various supply and demand regions, and the transportation costs and efficiencies of the various stages required to transport gas between them.[6]

The benefits of such an approach are multifold:

- the geographical diversity of natural gas supply and demand can be represented;
- all present and potential technologies for producing and consuming gas such as "tight sands" production, coal gasification and new heating or cooling applications can be represented;
- all present and potential transportation possibilities can be represented;

Figure 6.1
Typical Chain of Processes


WARM ROOMS
$10.72/MMBtu
CONVENTIONAL GAS FURNACE IN CHICAGO
CONVENTIONAL GAS FURNACE
COST = $3.83
EFFIC. = 0.66
$4.55/Mcf
DISTRIBUTION IN CHICAGO
DISTRIBUTION
COST = $1.00
EFFIC. = 0.975
$3.46/Mcf
TRANSMISSION TO CHICAGO
TRANSMISSION
COST = $0.50
EFFIC. = 0.95
$2.81/Mcf
GULF COAST NATURAL GAS PRODUCTION
GULF COAST NATURAL GAS

SOURCE: DFI, The GRI North American Regional Gas Supply-Demand Model, Figure 2-1.

- the inputs to the model are based on engineering and geological judgements of the cost and performance parameters of existing and potential supply, demand and transportation technologies; and finally
- unlike other models, the forecasting approach is predicated on the assumption that producer and consumer behaviour, market shares and technologies are driven by prices in the market.

6.2 The GRI North American Regional Natural Gas Model

The model used for our analysis is a multi-regional natural gas supply-demand application of GEMS that was originally developed by DFI under the sponsorship of the Gas Research Institute (GRI) for use as a planning tool to quantify the benefits likely to accrue from GRI's research initiatives.[7] The early versions of this model contained a very detailed regional representation of the U.S. but relatively aggregate representations of Canada and Mexico. Canada was characterized using several points of export to the U.S. Each export point was represented using an exogenous schedule of export prices with supply assumed elastic at that price for quantities less than an exogenously assumed upper bound on export volume. In essence, the U.S. model was a "giant demand function" with regard to Canadian and Mexican gas.

It soon became clear that this model had to be generalized to represent how responsive Canadian and Mexican supply might be to price. DFI, GRI, and others also recognized that the Canadian resource base was potentially very large, very diverse geographically, and less costly than much of the gas resource in the U.S. Moreover, to properly represent Canada and its relationship to the U.S., a comprehensive integrated representation of the Canadian natural gas supply, demand, transportation and export system was needed. It was thus necessary to also construct a multi-regional demand model of Canada and to link it with current and potential transportation alternatives.

This need for a full continental representation of the natural gas industry resulted in a cooperative effort by DFI, GRI, and the University of Saskatchewan in which the University undertook the construction of the Canadian component. This refined model represented the status of the North American Regional Natural Gas Model at the end of 1986. Shortly thereafter, the University of Saskatchewan and DFI approached CERI with a proposal to undertake a study of the natural gas industry using this model. GRI became a partner in this collaborative effort by granting CERI permission to use the model and the data they had generated for the model. Recognizing the timeliness of such a study given the current state of the industry and the opportunity to utilize a powerful analytical tool, CERI accepted and subsequently undertook the task of reviewing and further enhancing the Canadian component to the model. The resulting model is described in this section. Contributions, such as this, to the continuous evolution and enhancement of the network structure and technological data underlying the regional natural gas model are, and will continue to be, necessary to capture the inherent complexity and dynamic reality of the natural gas industry.

6.2.1 Model Structure

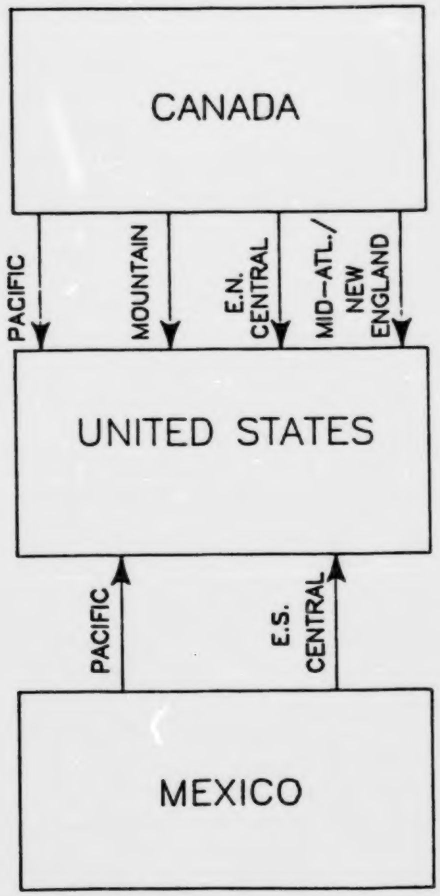
The North American Regional Natural Gas Model consists of three components; the United States, Canada, and Mexico. These components are then merged to create the GRI North American Gas Supply- Demand Model, an interactive representation of the full continental natural gas industry (Figure 6.2).

6.2.1.1 United States Regional Structure

The United States is disaggregated into twelve supply (excluding Canada and Mexico) and seven demand regions which are linked together according to the existing pipeline network and proposed or potential transmission connections. These regions and associated linkages are illustrated in Figure 6.3. For those linkages that currently exist, transportation costs were estimated as the average cost of transportation on actual pipelines providing service between those regions. Where future construction is required to establish a link, the per-unit capital costs and associated operating costs of such a project are provided as an input.

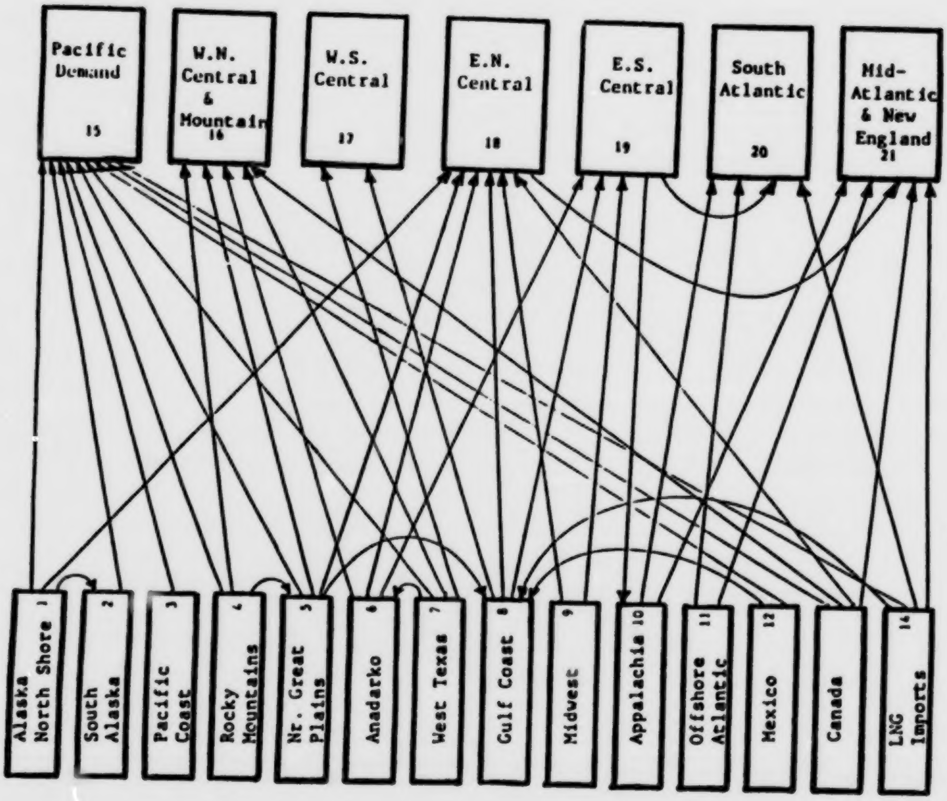
The primary source for the United States information has been GRI. To date, GRI has invested over $2 million in the development of the model and its supporting data base. This includes both the structural development of the model, the development of the GRI Hydrocarbon Model, and extensive R&D to characterize conventional and nonconventional U.S. gas resources. Three primary sources were used by

Figure 6.2
Interregional Structure of the Model


CANADA
PACIFIC
MOUNTAIN
E.N. CENTRAL
MID-ATL./ NEW ENGLAND
UNITED STATES
PACIFIC
E.S. CENTRAL
MEXICO

SOURCE: DFI, The GRI North American Regional Gas Supply-Demand Model, Figure 3-2.

Figure 6.3
United States Regional Structure


Pacific Demand
15
W.N. Central & Mountain
16
W.S. Central
17
E.N. Central
18
E.S. Central
19
South Atlantic
20
Mid-Atlantic & New England
21
Alaska North Shore
1
South Alaska
2
Pacific Coast
3
Rocky Mountains
4
Nr. Great Plains
5
Anadarko
6
West Texas
7
Gulf Coast
8
Midwest
9
Appalachia
10
Offshore Atlantic
11
Mexico
12
Canada
LNG Imports
14

SOURCE: DFI, *The GRI North American Regional Gas Supply-Demand Model*, Figure 3-3.

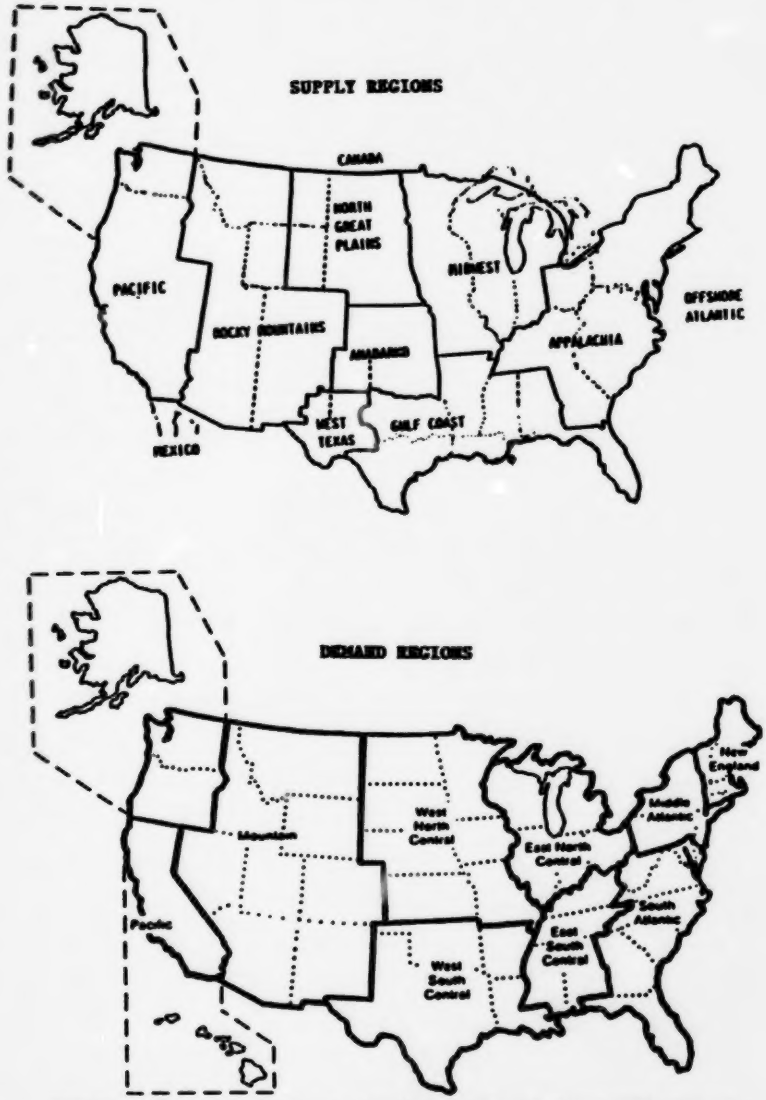
GRI to develop the information required to operate the regional natural gas model:

- GRI Hydrocarbon Model. The model presents the resource cost of finding, developing, and producing natural gas in the Lower-48 United States. This information has been used to provide detailed estimates of the United States gas resource base and associated production costs. GRI provided one set of Hydrocarbon Model results that had been used for its internal planning activities for use in this study.
- GRI Technology Cost and Performance Estimates. Specific cost and performance information has been assembled through GRI program area personnel as a result of R&D on the United States nonconventional and substitute natural gas resource base and associated production costs.
- GRI Baseline Projection. The baseline projection provides the regional gas consumption data, the interfuel competition assumptions, and the macroeconomic assumptions upon which the model is based.

The twelve supply regions used to describe the United States gas resource base represent a myriad of conventional, nonconventional, and synthetic gas sources. The regional boundaries were established for a number of reasons. First, it was necessary to distinguish differences in transportation costs between the alternative supply and demand regions. Second, regional distinctions were made if new pipelines or new pipeline capacity might be required to service a particular region in the future. Third, production economics and geological characteristics differ considerably between supply regions, and finally, the external environment with respect to taxes, royalties, and political policy characteristics may differ between regions and must be accounted for.

One further justification for the model's regional supply boundaries concerns the regional delineation of supply sectors by the Potential Gas Committee (PGC) in the United States. The PGC established specific regions and designations for the conventional and deep natural gas resource base after much thought to the appropriate level of regional disaggregation. These PGC regions are used in the GRI Hydrocarbon Model. As the Hydrocarbon Model provides a significant input to the GRI North American Regional Supply-Demand Model, a fully automated link between the two was recognized as highly valuable. The resultant supply regions for the U.S. are shown on the map in Figure 6.4.

Figure 6.4
U.S. Supply and Demand Regions


SUPPLY REGIONS
CANADA
NORTH GREAT PLAINS
PACIFIC
ROCKY MOUNTAINS
MIDWEST
OFFSHORE ATLANTIC
APPALACHIA
ANADARKO
WEST TEXAS
GULF COAST
MEXICO
DEMAND REGIONS
New England
Middle Atlantic
West North Central
Mountain
East North Central
South Atlantic
Pacific
East South Central
West South Central

SOURCE: DFI, *The GRI North American Regional Gas Supply-Demand Model*.

The data requirements for the supply process are resource cost curves for each gas source, relating the marginal cost of the undiscovered remaining gas resource base to cumulative production of that resource. As noted above, the GRI Hydrocarbon Model was used to develop the cost curves for the remaining Lower-48 conventional gas resources. GRI technology cost and performance estimates were used to construct cost curves for nonconventional gas sources such as tight sands, coal gasification, and methane from coal seams. Interested readers should contact Dr. Daniel Dreyfus of GRI's Washington office for further information regarding this data.

Seven demand regions are used to represent gas consumption in the United States. These regions generally follow the United States census region boundaries for a number of reasons. First, there is a historical precedent to using these regions and, consequently, a large volume of regionally aggregated consumption data. Second, generally similar climatic conditions are encompassed by the regional boundaries; thus, the attributes of the demand curve can accurately reflect the consumption characteristics implicit in each region. Third, the census boundaries generally encompass areas of similar industrial activity and sectoral gas usage.

The seven demand regions identified in the model are also shown in Figure 6.4. In some cases, the United States census regions have been aggregated within the model to form one demand region. This is done in cases where the level of detail would be inconsistent with assumptions or aggregations implicit at other points in the model. The final selection of regions, therefore, balances the benefits of increased detail with the costs of repetitive or unnecessary information.

The demand data for the U.S. consists of a reference demand path for each consumption region. These demand paths represent the assumed end-use demand quantities over the time horizon of the model and are input as exogenous variables. The model allows the user to specify either an elastic or inelastic demand process. As this study seeks to assess the impact of various policy alternatives on a reference case, it is essential that some price sensitivity of demand be modelled. To implement the elastic demand process, an exogenous price path for the reference demand path must be input. This price is obtained from the reference case. Differences between the prices calculated in the sensitivity cases and the reference case result in movements away from the reference demand path depending on the price elasticity of demand. The price elasticities input for U.S. gas demand are assumed to be constant across consuming regions and represent the response of total gas demand within a region to a change in price. The values assumed for the own-price demand elasticity parameters are -0.10 for the short-run and -0.60 for the long-run.[8]

The primary source for U.S. demand data is the 1986 GRI Baseline Projection of United States energy supply and demand. The baseline forecast is a consistent analytical framework used in addressing a forecast of future energy supply and demand in the United States. GRI uses the forecast for strategic planning, particularly with respect to natural gas supply and end-use technologies. A primary output of the forecast is the projected natural gas demands and prices by United States census region and end-use sector. These projections are input directly into the GRI North American Natural Gas Supply-Demand Model. The regional demand data input for the seven United States regions is presented in Table 6.1, which is a consolidation of the various sectoral forecasts contained in Chapter 4.

6.2.1.2 Canadian Regional Structure

The Canadian component of the regional gas model consists of five supply and three demand regions and is linked to the U.S. component according to existing gas export facilities and possible future connections such as the Iroquois pipeline proposal. This structure is illustrated in Figure 6.5. Canadian gas thus has access to 4 U.S. demand regions:

- Pacific
- West North Central/Mountain
- East North Central
- Mid Atlantic/New England regions

The regional disaggregation chosen for Canadian gas demand is based primarily on regional differences in natural gas availability, climate and usage characteristics. Within the Western Canada and Ontario demand regions, natural gas demand is further disaggregated into three end-use sectors; the residential, commercial and industrial sectors. This level of disaggregation is necessary to account for differences in the response of natural gas demand to changes in price (as was discussed in Chapter 4), and to account for differences in transportation costs to the burner-tip and resulting differences in

TABLE 6.1
1986 GRI BASELINE FORECAST OF NATURAL GAS DEMAND

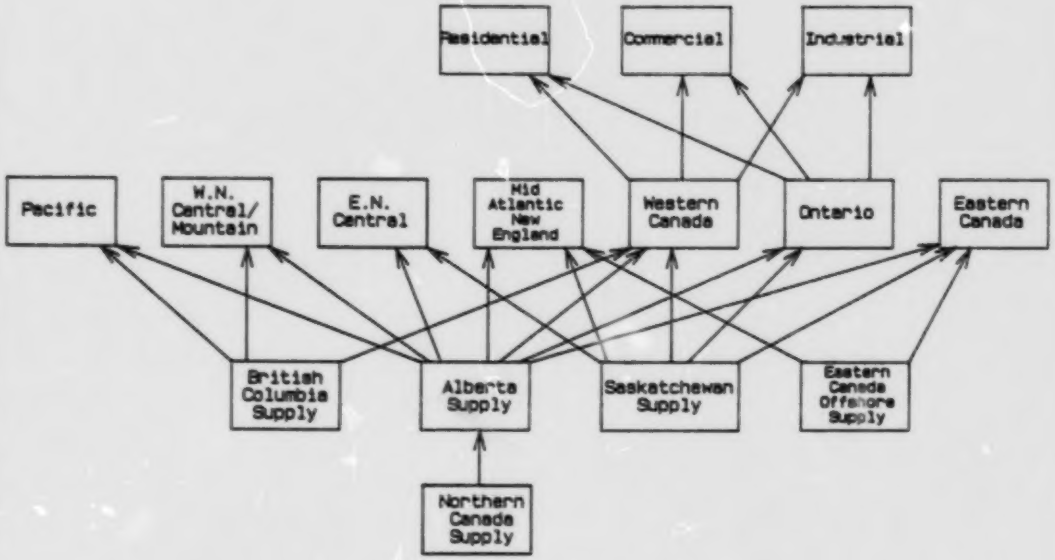
Demand Region	1985	1990	1995	2000	2005	2010
Natural Gas Demand[a] (quadrillion Btus)						
Mid Atlantic/New England	2.045	2.218	2.279	2.430	2.177	2.656
East North Central	3.137	3.078	2.997	2.792	2.638	2.546
West North Central/Mountain	1.737	1.686	1.654	1.579	1.485	1.429
Pacific	1.710	2.133	2.359	2.506	2.524	2.366
South Atlantic	1.296	1.503	1.558	1.608	1.582	1.683
East South Central	.782	.740	.741	.844	.811	.932
West South Central	5.038	4.543	4.666	5.192	5.256	5.175
	15.945	15.900	16.154	16.951	16.473	16.787

SOURCE: 1986 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010, (Baseline Projection Data Book).

[a] Excludes lease and plant fuel use.

Figure 6.5

Regional Structure of the Canadian Gas Model


Residential
Commercial
Industrial
Pacific
W.N. Central/ Mountain
E.N. Central
Mid Atlantic New England
Western Canada
Ontario
Eastern Canada
British Columbia Supply
Alberta Supply
Saskatchewan Supply
Eastern Canada Offshore Supply
Northern Canada Supply

SOURCE: Canadian Energy Research Institute.

burner-tip prices between sectors. As before, price elasticities were assumed to be constant across regions. Table 6.2 presents the price elasticities assumed for the different sectors.[9]

TABLE 6.2
SECTORAL PRICE ELASTICITIES FOR CANADIAN DEMAND

	Short-Run Elasticity	Long-Run Elasticity
Residential	- 0.05	- 0.55
Commercial	- 0.10	- 0.60
Industrial	- 0.25	- 0.70

SOURCE: Canadian Energy Research Institute.

Reference demand paths for the various sectors and regions contained in the Canadian demand sector were prepared through use of CERI's CREED model, a regional end-use, multi-fuel model that accounts for interfuel substitution possibilities. The demand forecast and associated assumptions are discussed in Chapter 4.

The linkages between Canadian supply regions and potential sources of gas demand (illustrated in Figure 6.5) represent the current domestic and export transportation network and proposed or potential future transmission connections, such as the Polar Gas proposal connecting the northern supply region to Alberta or the Venture proposal to supply the Eastern Canadian and New England/Mid Atlantic regions with gas from the Eastern offshore region. Within Canada, the additional cost of distributing gas to the burner-tip must be accounted for since we consider demand on a sectoral basis in Western Canada and Ontario. Table 6.3 presents the domestic wellhead to burner-tip transportation costs that are utilized in the model.

Also required as inputs to the model are the transportation costs associated with Canadian natural gas exports, the volumetric capacity of the existing export transportation network, and the cost of constructing new pipeline capacity. Table 6.4 presents the transportation costs estimated for natural gas exports and current export capacity. The capital costs and capacities of projects to develop the northern and eastern offshore gas resources are discussed in Chapter 3.

TABLE 6.3

CANADIAN TRANSPORTATION COSTS[a]
($1985 U.S. per MMBtu)

	Residential	Commercial	Industrial
B.C. to Western Canada[b]	1.87	1.15	0.40
Alberta to Western Canada[b]	1.87	1.15	0.40
Alberta to Ontario	3.01	1.99	1.35
Alberta to Eastern Canada[c]	—	1.80	—
Saskatchewan to Western Canada[b]	1.87	1.15	0.40
Saskatchewan to Ontario[d]	2.81	1.79	1.15

SOURCE: Canadian Energy Research Institute, 1987.

[a] Transportation Cost = Gathering Costs + NOVA Cost + TCPL Cost + Distribution Margin. (for B.C., Cost = Westcoast Gathering Charge + Westcoast Transmission Cost + Distribution Margin.). Effective date: September 87.

- 100 percent load factor assumed in all cases
- for Alberta, gathering costs assumed to $ 0.15/Mcf (U.S.).
- for B.C., Westcoast gathering charge assumed to be $ 0.075/Mcf U.S.
- Average distribution margins calculated from various distribution companies annual reports and the EMR Statistical Handbook--Representative Natural Gas Prices

[b] Demand weighted average of transportation costs to each province.

[c] Demand weighted average of transportation costs to each sector.

[d] TCPL charge is equal to cost to Eastern zone, minus cost to Saskatchewan zone.

TABLE 6.4

AVERAGE TRANSPORTATION COSTS AND CURRENT PIPELINE CAPACITY OF CANADIAN NATURAL GAS EXPORTS

	Transportation Cost[a] ($1985 U.S. per MMBtu)	Pipeline[b] Capacity (quadrillion Btus/year)
B.C. to Pacific	0.55	0.262
B.C. to West North Central	0.49	0.030
Alberta to Pacific	0.82	0.584
Alberta to West North Central	1.20	0.274
Alberta to East West Central	1.55	0.509
Alberta to Mid-Atlantic	1.75	0.075
Total		1.734

SOURCES: (1) Canadian Energy Research Institute, 1987 and (2) National Energy Board.

[a] 100 percent load factor assumed for all transportation cost calculations. Transportation Cost = Gathering Costs + NOVA Cost + (ANG Foothills TCPL) + U.S. Cost from Border to Regional Load Centre. (for B.C.; Cost to Border = Westcoast Gathering + Transmission Cost.)

U.S. Transportation Costs obtained from a variety of sources: Fosters and Associates; Natural Gas Information Service; Natural Gas Market; Pipeline Guide EnerNet Corporation; Natural Gas Information System.

[b] National Energy Board Estimates.

It was assumed that the Iroquois proposal or a similar type of project to export Alberta gas to the Mid Atlantic/New England region would eventually be accepted. The salient statistics regarding these three proposals are summarized in Table 6.5.

The rationale behind the supply sectors follows the same reasoning as that used in developing the U.S. structure. That is, each supply region represents a resource base that must be distinguished from the others due to differences in transportation costs, production costs and quantities, or regional policies and regulations. This last characteristic is particularly important for the Canadian network given the significant control that each province has over its own natural resources.

Figure 6.6 decribes the Canadian supply sectors. Within each supply sector, an array of supply sources can be modelled. This feature is utilized within the Alberta supply sector to model the potential for unconventional tight gas supplies. The northern region is disaggregated into two increments, Mackenzie Delta gas and Beaufort Sea gas.

As there is no Canadian counterpart to the GRI Hydrocarbon model, the estimation of the Canadian resource cost curves is limited to the projection of current finding and development costs over remaining undiscovered resources. These costs were estimated with CPA data and the advice of various industry experts. The Geological Survey of Canada's estimates of Canadian gas potential provided an upper bound to undiscovered Canadian gas. Canadian finding and development costs are analyzed in Chapter 3 and Appendix E.

Table 6.6 provides a breakdown of existing Canadian gas resources by the supply regions utilized in the model, and the resource cost curves used in formulating the reference case. These curves, which relate the marginal cost of remaining undiscovered gas resources to cumulative production of those resources, consist of two components: a per unit capital cost which consists of all fixed costs associated with the discovery and development of a unit of reserves, and a per unit operating cost associated with variable costs. Note that the capital costs are essentially in-ground costs. A by-product credit is applied to operating costs to represent the value of by-products such as natural gas liquids that are recovered in natural gas processing plants. Essentially, the increments in each cost curve represent the

TABLE 6.5
ESTIMATED COST OF POSSIBLE FUTURE PIPELINE PROJECTS

	Polar Gas[a]	Venture[b]	Iroquois[c]
Capital Costs ($U.S. millions)	2550	1040	654.9
Capacity (Quads/year)	0.292	0.110	0.128

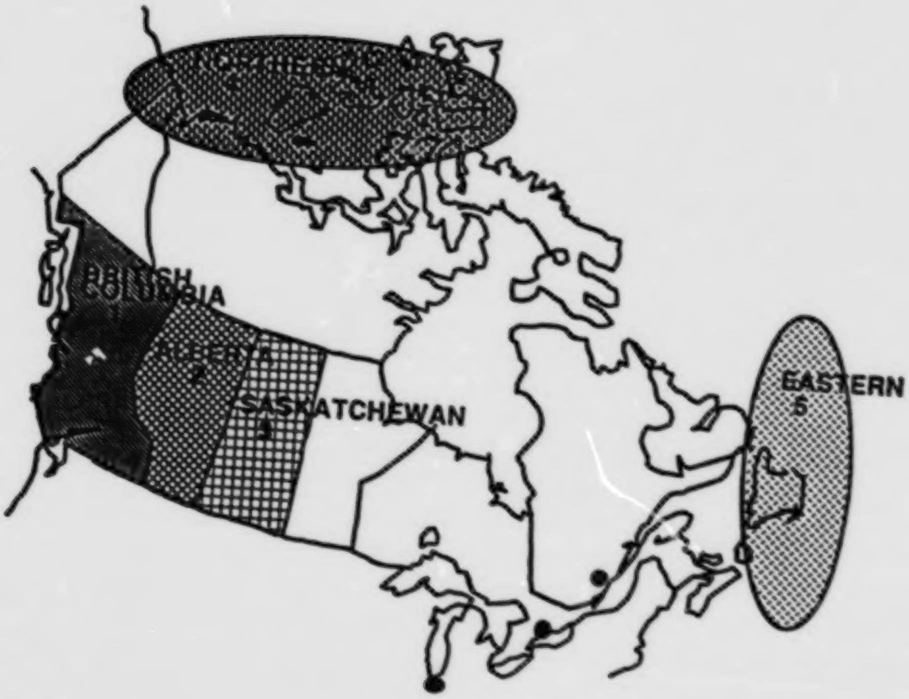
SOURCES: (1) Canadian Energy Research Institute, 1987 and (2) the National Energy Board.

[a] From Polar Gas proposal to NEB

[b] From Mobil proposal to NEB for Venture Project. Includes undersea pipeline, sales gas pipeline to U.S. border and U.S. pipeline to connect with existing pipelines in Massachusetts. It is assumed that the cost of U.S. pipeline would equal the cost of sales gas pipeline.

[c] From Iroquois Gas Transmission (IGTS) Fact Sheet (includes costs for TCPL and other facilities of $CDN 363 million.)

Figure 6.6
Canadian Supply Regions


BRITISH COLUMBIA
1
ALBERTA
2
SASKATCHEWAN
3
EASTERN
5

SOURCE: R. C. Rinholme, 1987.

TABLE 6.6
CANADIAN RESOURCE COST CURVES

	Cumulative Reserves Additions	Capital Cost	Operating Cost
	(quadrillion Btus)	($1985 U.S. per MMBtu)	
B.C.	2.50	0.31	0.25
	10.50	0.73	0.27
	15.50	0.88	0.29
	19.50	0.99	0.33
	22.50	2.19	0.37
Alberta Conventional	9.00	0.26	0.04
	20.00	0.33	0.07
	30.00	0.62	0.11
	45.00	0.73	0.15
	65.00	0.83	0.24
	85.00	0.95	0.26
	100.00	2.19	0.37
Alberta Unconventional	4.00	0.95	0.37
	10.00	1.28	0.39
	20.00	1.83	0.40
	30.00	2.97	0.42
	50.00	4.38	0.44
Saskatchewan	0.06	0.15	0.11
	0.76	0.44	0.11
	1.26	0.55	0.17
	2.26	0.73	0.20
	3.00	0.88	0.23
Northern MacKenzie Delta	5.40	1.42	0.18
	10.40	2.12	0.28
	12.00	2.83	0.37
	15.00	4.00	0.70
Northern Beaufort Sea	5.00	1.69	0.66
	10.00	2.55	0.70
	15.00	3.36	0.77
Eastern Offshore	2.36	0.58	0.07
	8.00	0.69	0.55
	18.00	0.99	0.73

SOURCE: Canadian Energy Research Institute, 1987.

total undiscovered gas reserves that will ever be discovered, developed, and produced at costs up to that level.

We assume 50 quads Tcf of tight sands gas in the Alberta deep basin can eventually be produced at capital costs ranging from $0.95 to $4.38 (1985 $U.S.) per MMBtu. Only those reserves that have been discovered to date are considered in the frontier areas. Capital costs in these regions vary from $0.58 to $4.00 per MMBtu. The surplus of gas in conventional reserves is represented by the low cost of available gas, 20 quads in Alberta and 2.5 quads in B.C., respectively. These reserves have already been discovered and require only development and connection to the gathering system before production can proceed. Undiscovered gas potential in Alberta is assumed to be 80 quads and the capital cost of this gas ranges from $0.62 per MMBtu to $2.19 per MMBtu. In B.C., 20 quads of gas are assumed to be ultimately recoverable at costs ranging from $0.73 to $2.19 per MMBtu. The higher capital costs encountered as you move along the resource cost curves represent the impact of depletion over time as drilling activity must be directed towards deeper formations in less hospitable environments, and as the returns to drilling--the discoveries per well drilled--decline.

6.2.2 Features of the Model: Strengths and Weaknesses

Many of the features of the GEMS framework are well suited to modelling the natural gas industry. From a supply side perspective the need for detail is obvious--different supply sources have different capabilities and costs. Moreover, accurate representation of the location of these sources relative to the major gas consuming regions and the existing transportation network is crucial to the exercise, as the principal supply alternatives differ considerably in their distance from major demand centers. Long-term alternatives such as North Alaskan gas and Canadian frontier gas require substantial capital investments to connect them into the existing transportation network. The costs of these facilities must be accounted for in the delivered price of gas from such locations. It is this cost relative to the price of competing supply sources that determines the demand for frontier gas and, hence, the viability of such large scale projects.

There is also a need for a spatial framework from a demand side perspective. The major U.S. markets for Canadian gas have different factors impacting on gas demand such as variations in alternative fuel costs, sectoral growth patterns, or electricity generating capacity. The proximity of alternative supply sources, their costs and the corresponding transportation costs present consumers within the various demand regions with an array of supply alternatives, at different prices, from which to satisfy regional demand.

The GEMS network structure satisfies all of these needs. As the previous section describes, the user defines the spatial structure of demand and supply, and inputs as parameters to the model the demand and supply characteristics of this structure and the relative transportation costs linking them together. Within this framework, Canadian gas exports flow to those U.S. demand regions in which the transportation network allows them to compete. Canadian gas is one of the many different supply alternatives to which these regions have access. It follows that any government policy moving the price of Canadian gas from its free market level will result in its displacement by (or its displacement of) competitively priced alternative supplies.

Each of the supply and demand curves in the gas model represents the parameters faced by a profit maximizing producer or cost minimizing consumer. Producer behavior is modelled according to a Hotelling-type rule of resource production. Production is assumed to be set to maximize the discounted present value of future profits from selling that gas. Each producer must form expectations of future costs of production, demand, and prices in making this decision. These expectations are modelled by assuming they are formed in a rational manner. That is, it is assumed that producers do not make consistent mistakes when forming expectations of future variables that impact on the present value of their profit stream. The production level that they choose is therefore the optimum one given the parameters they face.

The solution to this profit maximization process is the widely accepted result that price equals marginal production costs plus scarcity rent. That is, the producer sets his production schedule so that in every year he is compensated for the higher gas replacement costs he must bear in future years. Thus, the value of the last unit of gas produced must be just equal to the value a producer would receive from that marginal unit if he deferred production for a year.[10]

The scarcity rent represents the above normal profits that could accrue to the resource owner in an idealized world. In the real world, however, producers and resource owners are generally distinct.

The resource producer is concerned with earning a sufficient rate of return on investment while the resource owner attempts to recover potential rents through the lease bidding process and royalty payments. Uncertainty regarding future prices, production costs and demand, and the prices of competing energy sources (including other gas supplies) constrain the ability of the owner to collect the optimal rent premium. The compression of rents from gas production is widely apparent in today's gas market.

The model has a number of features which allow the effects of the perfect foresight assumption to be moderated, such as lagged responses by producers and constraints on production and transportation.[11] In this version of the model we have placed capacity constraints on existing pipelines and specified new pipeline construction costs for potential or proposed pipeline projects.

Consumers in the model face a wide array of supply alternatives from which they must satisfy regional demand. In doing so, they attempt to minimize their gas purchase costs. Because they cannot generally satisfy all of their gas requirements from one source, they must allocate their gas demand among the various supply alternatives. This allocation process is modelled according to the relative costs of gas from accessible supply regions and essentially represents gas-on-gas competition.[12]

The solution to the GEMS model is based on the principle that demand and supply must be equated over the time horizon of the model. An iterative process is used to balance these supply and demand forces and the solution is not complete until all relationships in the model are simultaneously and exactly in equilibrium. The prices obtained clear all markets and there is no incentive for either producers or consumers to change their production or consumption decisions. Given the level of detail inherent in the model structure, this is a very complex process. Optimal behaviour by the individual producers and consumers is dependent on the actions taken by others. Further, GEMS accounts for the dynamic effects of time on production and consumption decisions, regulatory and tax effects, and financial and technological variables, and determines their impact on equilibrium market conditions.

Obviously, the equilibrium condition that determines the solution to the GRI gas model is not present in today's natural gas market, as evidenced by the surplus productive capacity present in both Canada and the U.S. The model is not particularly well suited to a short-run analysis of the impact that these surpluses and current low prices will have on drilling activity and reserves additions in the near term. However, in the long term, such a situation cannot persist. The gas bubble, especially in the U.S., must eventually disappear because of current poor returns to exploratory drilling and a subsequent decline in the level of reserves replacement. In a deregulated market rising prices will signal the end of the bubble and, ultimately, some form of equilibrium situation should emerge. Prices in this environment will have to be at a level that will allow natural gas to compete with alternative fuels in end use markets, and yet be sufficiently high to return to the producer the true costs of production, including a return on investment adequate to attract new capital for future exploration activity in competition with other investment opportunities. It is this type of long-term relationship that the model captures.

It must be remembered that, like any model, the one used in this study has certain weaknesses. First, the model gives a best guess of the future conditional on the specific resource, technology, demand, and transportation assumptions underlying it. The results will be biased to the extent that this data differs from industry perceptions and reality. Second, relative transportation costs are assumed to be constant throughout the time horizon of the model. Any changes in the relative cost structure will result in changes to gas market shares and prices that cannot be accounted for. Exchange rates are also assumed to be constant over the modelling time horizon. Any movement in exchange rates will impact on the cost of Canadian gas relative to U.S. gas and, hence, on the competitive position of Canadian gas in the U.S. market.

Given the movement towards a deregulated market in both the U.S. and Canada, a model such as the regional natural gas model, which accounts for the myriad of alternative supply sources and their spatial relationship with consuming regions and that determines price as the outcome of supply satisfying demand, is an invaluable tool in assessing the potential development and prospects for the North American natural gas industry. From a Canadian perspective, the model is particularly valuable. It allows for the consistent assessment of:

- long-term Canadian natural gas export potential to the various U.S. demand regions under a variety of scenarios;

- the impact that U.S. market conditions will have on Canadian prices under these different scenarios;
- the costs and benefits to Canadian producers and consumers of different levels of gas exports to the U.S.; and
- the timing and viability of Canada's unconventional and frontier resources.

Footnotes

[1] E. G. Cazalet, Generalized Equilibrium Modelling: The Methodology of the SRI-Gulf Energy Model, (Decision Focus Inc. Palo Alto, 1977).

[2] U.S. Energy Information Administration, Annual Report to Congress 1978 (DOE/EIA-017313, 1978).

[3] An example of a large scale model of the elecricity sector built with this software can be found in C. E. Clark, R. B. Fancher and S. M. Haas, An Integrated Electric Utility Planning Model, Decision Focus Incorporated, (Palo Alto, 1981).

Other large scale models have been constructed to describe the energy sectors of Argentina, Portugal and South Korea. Specific policy applications include:

J. Barhen et al., "LFS, A Strategic Planning Capability for U.S. Liquid Fuels Supply," in Energy, (1982).

D. M. Nesbitt and R. L. Phillips, "A Decision Analysis of the Appropriate R & D Strategy for Advanced Oil Recovery," Energy Systems and Policy, (1981).

[4] A more in depth description of these three elements can be found in R. L. Phillips, A Methodology and Software System for Linking Economic Models (North Holland Publishing Company, 1983).

A more general and less technical description can be found in the following:

The Generalized Equilibrium Modelling System--Scope and Benefits; Decision Focus Inc, Palo Alto, 1984.

An overview of the Generalized Equilibrium Modelling System (GEMS), Decision Focus Inc., Palo Alto, 1983.

[5] D. M. Nesbitt, "The Economic Foundation of Generalized Equilibrium Modelling," Operation Research, vol. 32, no. 6, November-December, 1984 presents an in depth discussion of the economic theory and solution algorithm underlying GEMS.

[6] This discussion is greatly expanded in S. M. Haas, D. M. Nesbit and Jagjot Singh, The GRI North American Regional Natural Gas Supply-Demand Model, Decision Focus Inc, Palo Alto, (1987).

[7] See S. M. Haas, et al., The GRI North American Regional Natural Gas Supply-Demand Model, (1987).

[8] These are consistent with elasticities that have been estimated econometrically. See Bohi (1981) for a discussion of these various studies.

[9] Refer to Footnote 8.

[10] A discussion of the derivation of this version of Hotelling's rule and the implicit assumptions is provided in S. M. Haas et al., The GRI North American Regional Natural Gas Supply-Demand Model (1987), pp. 4-1 - 4-9. The actual implementation of the theory in the model is discussed in Chapter 5.

[11] Ibid., Chapter 6.

[12] Ibid., Chapter 7.

Chapter 7

RESULTS AND IMPLICATIONS

This chapter presents our long-range forecast of natural gas prices and quantities as calculated by the regional gas model, the impact of key sensitivities and policy alternatives on this forecast, and a discussion of the implications that these results hold for the Canadian natural gas industry. Our approach towards implementing the gas model was to first formulate a reference case that incorporated what CERI perceived to be the most accurate characterization of the Canadian gas industry. To address a number of key uncertainties such as the cost and size of undiscovered conventional and frontier resources, we constructed a series of sensitivity cases which allowed us to investigate the impact that these changes would have on future prices and quantities relative to the base case. Finally, a number of policy alternatives were examined to assess the impact they might have on the future evolution of the natural gas industry. The sensitivity cases and policy alternatives analyzed in this study were selected by the Institute in consultation with the Advisory Committee assembled for the research project.

7.1 Reference Case

The reference case for our analysis was defined by observing the current and evolving structure of the natural gas industry. As noted throughout the study, the system is moving inexorably toward a situation in which wellhead prices will be deregulated while pipeline and distribution rates continue to be regulated. Therefore, the reference case assumes deregulated wellhead prices throughout Canada and the United States. Furthermore, no limitations are imposed to restrict the quantities or prices of gas that could be exported from, or imported to, either country and Canadian gas is assumed to have open access to U.S. pipelines. In effect, the reference case is a free trade scenario. The data inputs underlying the reference case are presented in Chapter 6.

A key assumption that is required by the model is the rate at which future reserves additions are produced and the rate at which this production declines over time. Since U.S. reserves have traditionally been produced at or near full capacity, future reserves additions are assumed to be produced at historical regional production-to-reserves ratios. Production is assumed to decline exponentially over time at the same rate.

For the Canadian supply regions, a different methodology must be applied since a large portion of Canada's established reserves, which were found to satisfy the export surplus rules, have never been produced due to a lack of markets. Typical contract terms can call for a wide range of production rates, anywhere from the productive capacity of the gas reserves to a reserves-to-production ratio of 20 years. For the reference case, future reserves additions (and currently shut-in and unconnected but established gas reserves) were assumed to be produced at a production-to-reserves ratio of 0.067 (a reserves-to-production ratio of 15 years). The rate of production was assumed to decline over time at the same rate. This figure was arrived at through consultation with various industry officials and through consideration of likely future contract terms.

7.2 Sensitivity and Policy Cases

As noted above, sensitivity cases were required to assess the impact of key uncertainties on the reference case results. Our choices for these cases reflect the widely divergent views that exist about Canadian gas resources and focus on the costs and size of the undiscovered resource base. In particular, we wish to examine the impact of changing certain assumptions regarding the conventional and tight gas resource base on the timing of frontier gas production. Also, uncertainty about the future level of Mexican exports to the U.S. warranted analysis. Accordingly, a sensitivity case regarding the level of Mexican exports was developed to analyze where and to what extent Canadian gas would be displaced if Mexico were to offer more competitive prices for its natural gas exports.

A number of policy cases were run to examine the impact of various policy initiatives that might be taken by the Canadian government on the future evolution of the gas industry. Because natural gas royalties are assumed to be captured in the scarcity rent component of prices in the reference case, we first examine the impact of higher royalty rates in Canada than in the U.S.[1] Second, because the export surplus rule has played such a major role in the development of the Canadian gas resource base, we analyze the effects, and compare the costs and benefits of, a 25- and 10-year surplus test relative to the reference case. The 10-year surplus test essentially represents a free market scenario in which natural gas reserves are produced at or near full capacity, as is the case in the U.S. Finally, since an alternative method of limiting natural gas exports is to place a border tax upon them, we examined the impact and costs and benefits of such a tax.

Table 7.1 contains a summary of all the above cases and the changes that were made relative to the reference case. The case name, given in Column 1, is the name which is referred to in the presentation of the results.

7.3 Model Results

The regional natural gas model produces a wealth of information on prices and quantities in every demand and supply region through to the year 2030. In addition, the model calculates the reserves additions required in each supply region to support the estimated levels of production. We have abstracted from this information those results that are most pertinent to the Canadian gas industry. These are:

- burner-tip prices by sector and region in Canada;
- average wellhead prices and production by region in Canada;
- required reserves additions to support the above levels of production;
- natural gas exports and delivered price by U.S. demand region;
- price and quantities delivered by competing sources into the U.S. demand regions; and
- average wellhead prices and production by region and technology in the U.S.

The presentation in this chapter is mainly graphical. All tables from which these figures are produced are presented in Appendix H. Results from the sensitivity and policy cases are presented relative to the reference case. As before, tables are relegated to Appendix H. Because Chapter 4 presented and analyzed the forecasts of natural gas demand in Canada and the U.S. that are utilized within the model, this section focusses on the sourcing of production and the price levels required to meet the forecast demand.

TABLE 7.1
DESCRIPTION OF SENSITIVITY AND POLICY CASES

Case Name	Description of Case	Changes Made Relative to Base Case
UPCON	Impact of greater Canadian conventional gas supply and lower costs on exports and domestic prices.	Undiscovered resources in Alberta are increased by 30 Tcfs. This increase is allocated equally to the different cost increments presented in Table 6.6.
TIBC	Assessment of the potential for tight sands gas production in Alberta.	Assumes that 100 Tcf of tight gas will be found and eventually produced.
EASTUP	Sensitivity of the timing and demand for Eastern offshore gas.	Assumes that East Coast offshore capital and operating costs are 100% and 50% higher respectively than those presented in Table 6.6.
TOUT	Implications for timing and demand of Northern Canadian gas, assuming no tight sands gas becomes available.	No tight sands gas is assumed to be available over the forecast period.
MEXUP	Impact of greater Mexican exports on Canadian export volumes.	Assumes that Mexico offers a lower price for its natural gas exports.
POLICY CASE I ROYAL	Impact of higher royalty rates in Canada relative to U.S.	Effective royalty rates in B.C., Alberta and Saskatchewan increased to 16%.
POLICY CASE II 25SURP 10SURP	Impact of export surplus rule.	Comparison of 25 and 10 year r/p test to reference case.
POLICY CASE III XTAX	Impact of a natural gas export tax.	Impact of $.75 per MCF export tax relative to reference case.

SOURCE: Canadian Energy Research Institute, 1987.

NOTES: All cases referred to by case name in discussion of results.

In interpreting these results, it must be remembered that the model is a long-run, equilibrium representation of the North American natural gas market that is strictly dependent on the input data used to characterize natural gas supply, demand and transportation. To the extent that the reader disagrees with either the equilibrium condition or the input data, they are also likely to disagree with the results. However, the power of this modelling approach is that it provides a powerful framework for both a qualitative and quantitative assessment of the long-term potential impacts of different assumptions and policy initiatives on export levels, prices and quantities.

We have presented a standard set of detailed model results in Appendix H for each case examined in the analysis. It is hoped that these results will provide interested readers with a more intuitive feeling for how the model works and its sensitivity to different types of assumptions. This should provide readers holding contrasting views with a basis for simple thought experiments in which they can change an assumption and follow the model logic through to get a good idea of its impact on the analytical results.

While the equilibrium condition on which the model solution is premised might not fully materialize by 1990 (the first year that the model provides a price forecast), given the evolution toward a deregulated market, prices must eventually reach a level that reflects both the cost of alternative fuels and the cost of maintaining adequate supplies to meet current and future requirements. Moreover, it must be remembered that the prices calculated in this model represent the outcome of a profit maximization process in which producers are assumed to have perfect knowledge of all variables affecting the profit calculation. Further, although interfuel competition is accounted for in the demand forecasts, it is not (yet) explicitly taken into account in the regional model.

The resulting calculation of price consists of three components: an operating cost; a capital charge on the investment required to add production capacity (which includes a 10 percent real return on investment); and the scarcity rent. The scarcity rent in the model represents the theoretically obtainable excess profits that arise because the resource is depletable and increases in cost over time. The resource owner (the provinces in Canada) attempts to extract this rent through the lease bidding process and the imposition of royalties. It is this component of price that is compressed in the current environment of gas-on-gas competition and low oil prices because it is variable while the other components of price are essentially fixed. Note that over time, however, the capital charge component will increase as production costs increase and, concomitantly, the scarcity rent will decrease. Thus, although the prices calculated by the model may, in the short term, be unrealistically high, the longer-term prices are indicative of the underlying resource base. However, it should be emphasized that it is the relative costs of gas from different supply regions and between cases that are crucial to the analysis. That is, the cost of Canadian gas relative to U.S. gas in the U.S. importing regions determines the level of exports.

7.3.1 Reference Case Results

7.3.1.1 The Domestic Market Forecast

This section presents forecast data on potential burner-tip prices, average wellhead prices and production by sector and by region for Canada. Figures 7.1 and 7.2 provide forecasts of the burner-tip prices for Western Canada and Ontario on a sectoral basis. As illustrated, a sharp increase in gas prices is predicted between now and 1990. This is indicative of the current dislocation in the gas industry where surplus productive capacity has caused prices to fall well below levels which reflect the long-term supply/demand situation (as noted above). It is also a function of the model's pricing mechanism. Essentially the calculated prices represent the optimal value of natural gas as an exhaustible resource given the supply cost assumptions and future level of demand we have specified. Lower gas prices imply that a large portion of the scarcity rent component of prices is flowing to consumers rather than the resource owner. This is a situation that the Alberta Government has expressed considerable concern over as witnessed by the recent change in the natural gas royalty regime to establish a minimum price for royalty calculations. Prices after 1990 are forecast to increase at an average annual real rate of slightly less than 3 percent.

For reference purposes, the Btu equivalent oil price track utilized in the demand forecasts is also presented in each of the figures.[2] The results indicate that in Ontario and Eastern Canada, equilibrium burner-tip prices have the potential to impinge upon the price of the principal alternative, residual fuel oil, especially towards the beginning of the forecast period. This is a significant departure from the low gas prices evidenced today which are caused largely by competition between alternative gas sources at the wellhead

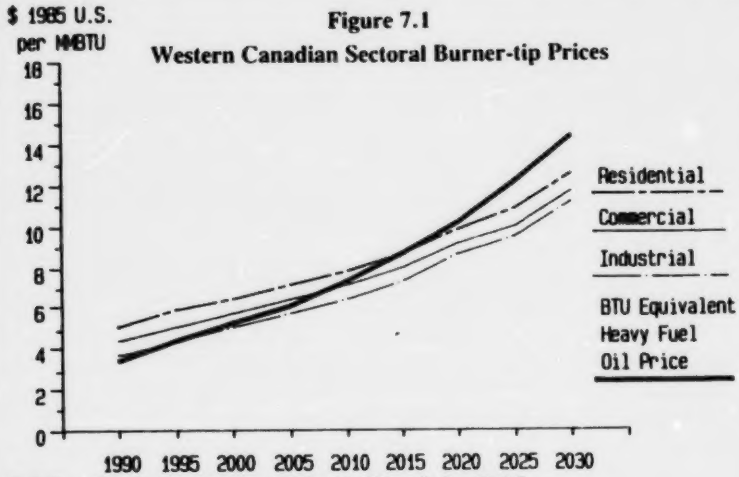


Figure 7.1
Western Canadian Sectoral Burner-tip Prices

SOURCE: GRI North American Regional Natural Gas Model.

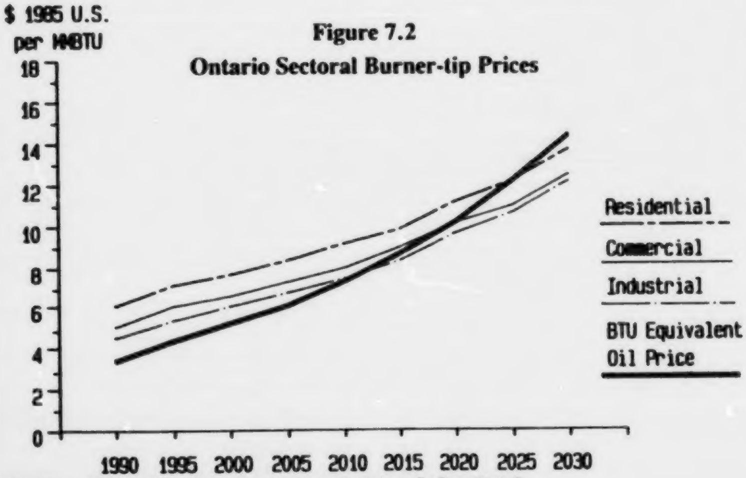


Figure 7.2
Ontario Sectoral Burner-tip Prices

SOURCE: GRI North American Regional Natural Gas Model.

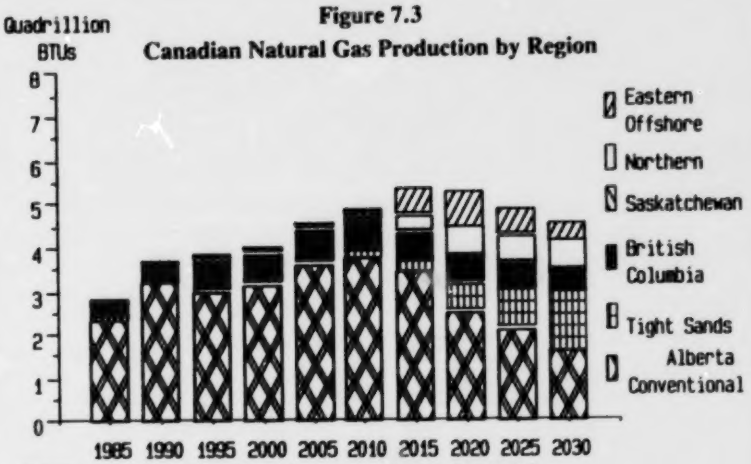
In the longer term, gas prices are generally lower than the price of residual fuel oil in the industrial market.

Figures 7.3 and 7.4 summarize the forecast for Canada's production sector. Figure 7.3 illustrates the forecast of Canadian production by supply region. Total Canadian production is projected to increase from 2.8 quads in 1985 to a peak of 5.4 quads in 2015. Conventional production from Alberta accounts for the bulk of this total, averaging about 75 percent of total production until 2010 when it peaks at 3.72 quads before declining thereafter to 1.64 quads in 2030. B.C. production peaks in about the same period as Alberta conventional at 0.757 quads, and supplies on average, about 15 percent of total Canadian production. It is then projected to decline to 0.437 quads by 2030. Saskatchewan production peaks in the year 2000 at 0.138 quads, more than double annual production in 1985. Production is maintained above 1985 levels throughout the forecast period although it slowly declines from this peak.

As discussed in Chapter 6, one of the attractive elements of the regional gas model is its ability to forecast the timing of production from alternative gas supplies. Because of the high cost of tight sands gas, production is not economic until 1995 when it is estimated to approach 0.1 quads. It is then forecast to increase throughout the time horizon of the model, peaking at 1.4 quads in 2030. The high cost of developing and connecting the frontier reserves of Northern Canada and the Eastern Offshore region into the established transportation network delays production from both regions until after 2010. Production from Northern Canada is expected to almost double within 5 years after startup, increasing from 0.33 quads in 2015 to 0.65 quads in 2020. Production from the Eastern Canadian Offshore region increases from 0.59 quads in 2015 to a peak of 0.8 quads in 2020 before declining to 0.42 quads by 2030.

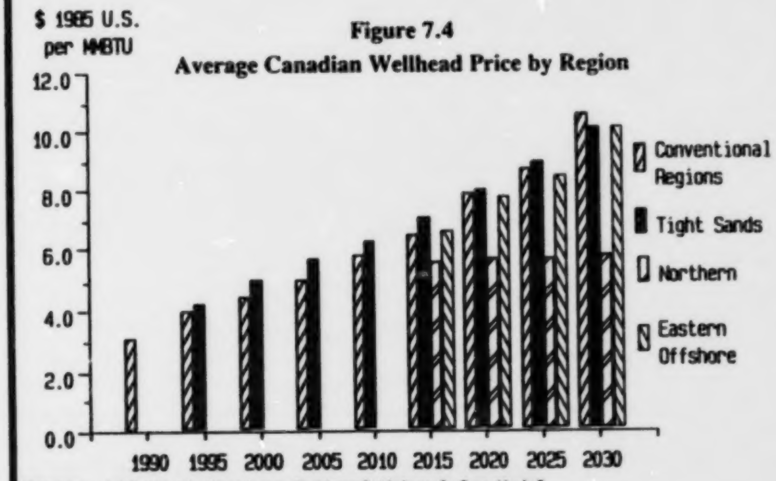
The forecast increase in burner-tip prices results from increases in the average wellhead price which producers are forecast to receive over time. These prices are illustrated in Figure 7.4 and serve to re-emphasize the point that current prices are significantly below the level required to maintain and increase the level of reserves necessary to support forecast demand requirements. The average Canadian wellhead price is forecast to increase to $3.15 ($1985 U.S.) by 1990 and increase at an annual rate of about 3 percent thereafter. The average wellhead price forecast for 1990 represents a nearly two fold increase in prices from 1986. Wellhead prices in the frontier

Figure 7.3
Canadian Natural Gas Production by Region



SOURCE: GRI North American Regional Natural Gas Model.

Figure 7.4
Average Canadian Wellhead Price by Region



SOURCE: GRI North American Regional Natural Gas Model.
NOTE: Conventional Regions include Alberta, B.C., and Saskatchewan.

regions are lower than those in the conventional regions, reflecting the large share of transportation costs in the final delivered cost and the degree to which producers will have to discount at the wellhead to realize expected sales.

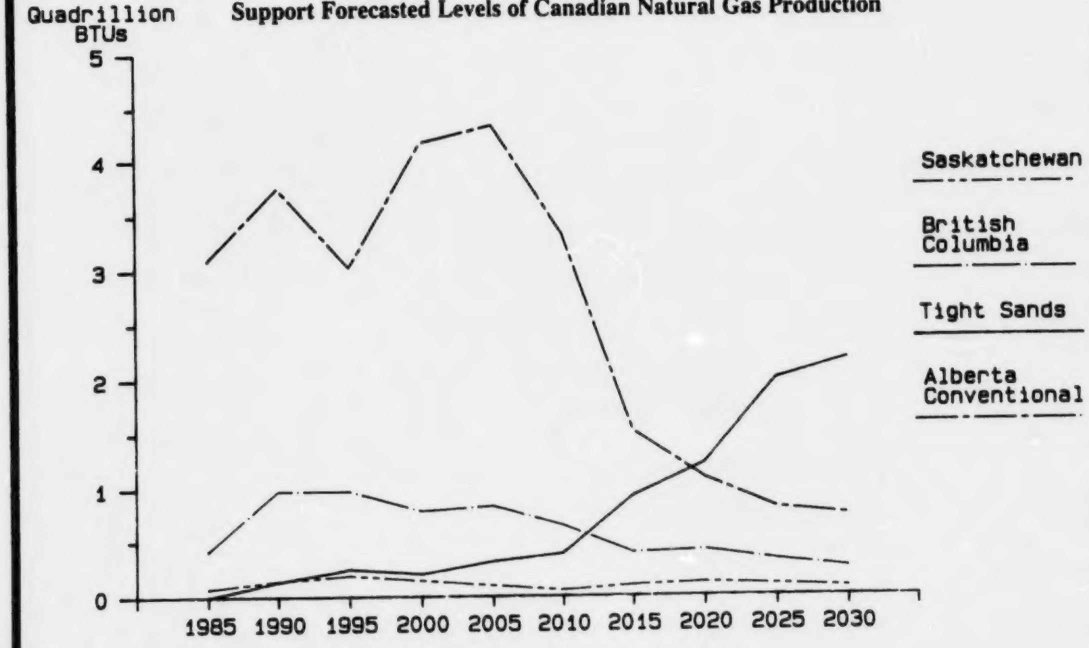
For the production levels appearing in Figure 7.3 to be realized, reserves will have to be added at a considerable rate to offset depletion in established reserves. These required annual reserves additions (for the conventional supply regions) are calculated by the model and are provided in Figure 7.5. As illustrated, Canadian producers will have to add over 5 quads annually until 2005, whereupon the rate declines to just over 3 quads by the end of the forecast horizon. The long-term implication that these figures have for the Canadian gas industry is simple--an intensive, sustained drilling program will be required to meet forecast production levels. If an average finding rate of 1.0 Tcf per successful gas well (about the average observed between 1980 and 1985) were to be maintained throughout the forecast period, over 6000 successful gas wells would be required on an annual basis in the Western Sedimentary Basin by 2005 compared to the 1300 completed in 1986. While this represents a lower bound on the number of required wells because finding rates are likely to decline over time as prospects for new discoveries diminish, it does illustrate the magnitude of the drilling effort that must be directed towards gas in the long term.

7.3.1.2 The Export Market: Volumes and Delivered Prices

Because of the scope of the regional gas model, we are able to present a detailed regional breakdown of forecast Canadian export volumes. This includes both delivered volumes and prices as well as the delivered volumes and prices of competing gas sources in each importing U.S. demand region. Figure 7.6 presents the forecast level of future exports broken down by U.S. demand region. Total forecast export volumes show three distinct peaks--1.4 quads in 1990, 1.5 quads in 2005, and 1.7 quads in 2015. This pattern emerges primarily because as prices increase, higher cost U.S. supply sources can be produced more intensively and thus displace some Canadian gas. Inevitably, production from these sources declines and additional Canadian gas supplies are again required to satisfy U.S. demand. Figure 7.7 presents the delivered price of Canadian gas into the four importing U.S. regions.

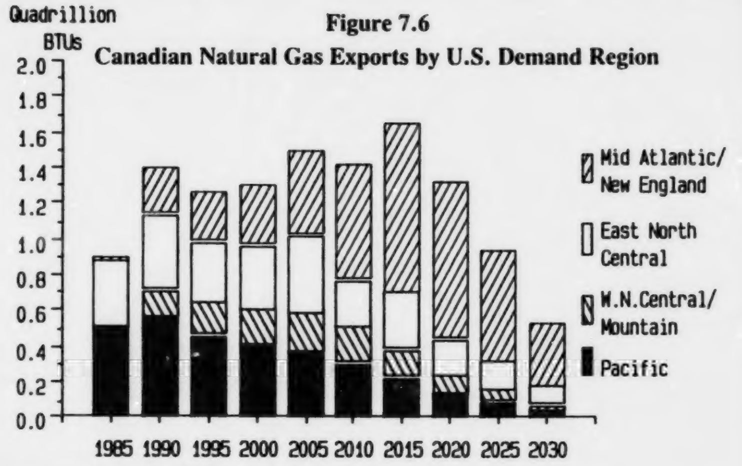
Figure 7.5

Average Annual Reserve Additions Required to Support Forecasted Levels of Canadian Natural Gas Production



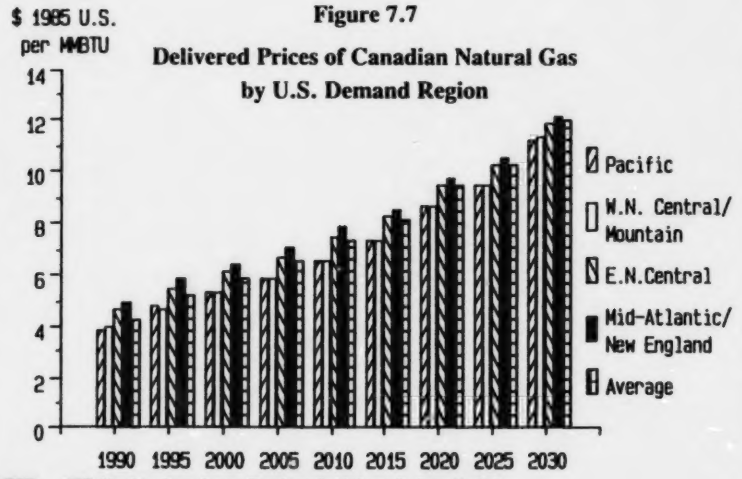
SOURCE: GRI North American Regional Natural Gas Model.

Figure 7.6
Canadian Natural Gas Exports by U.S. Demand Region



SOURCE: GRI North American Regional Natural Gas Model.

Figure 7.7
Delivered Prices of Canadian Natural Gas by U.S. Demand Region



SOURCE: GRI North American Regional Natural Gas Model.

The Mid Atlantic/New England region is identified as the major growth market for Canadian gas producers. As illustrated in Figure 7.6, annual sales are forecast to be 0.27 quads in 1990 and climb to a peak of 0.96 quads in 2015. By this time, Eastern Canadian Offshore production supplies the bulk of the region's import requirements.

The increase in Canadian exports to the Mid Atlantic/New England region is the result of three important trends. First, gas production from three principal supply regions in the U.S. having access to the Northeastern states--the Anadarko, Gulf Coast and West Texas regions--is forecast to decline over time. As the gas resource in these regions is depleted, higher gas costs will result. Second, natural gas demand in the Mid Atlantic/New England region is forecast to increase considerably from about 2 quads in 1985 to 2.4 quads by 2000. When combined with the fact that the existing transportation network in the U.S. does not permit gas from other supply regions besides the Appalachians to reach the Northeastern U.S. (and was constrained from doing so in the model network), the only other sources available to supply the remaining requirements are from either Canada or LNG imports.

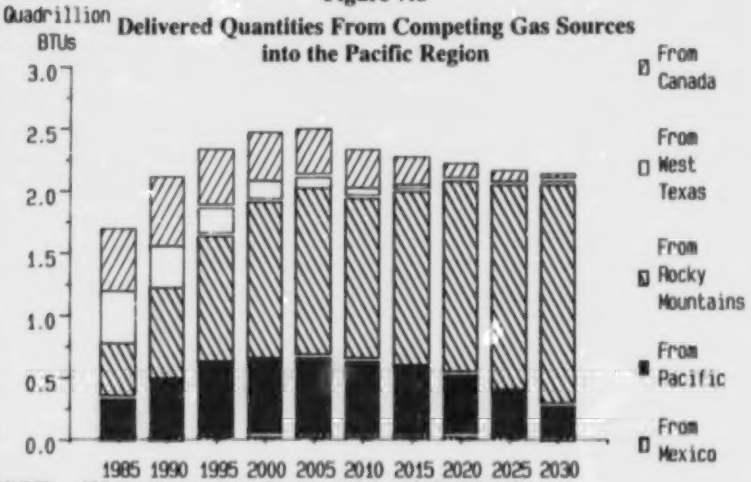
Declining natural gas demand in the East-North Central region results in a slight fall in export sales into this region over time. It is interesting to note that exports to the Western U.S. demand regions show similar trends over time. That is, except for 1990 when exports are forecast to increase, both the Pacific and the West-North Central/Mountain regions show a declining reliance on Canadian supply thoughout the forecast period. The Pacific region, however, remains the major consumer of Canadian gas until 2000, with demand peaking in 1990 at 0.6 quads and declining gradually to 0.41 quads by 2000.

The regional natural gas model determines the U.S. demand for Canadian gas regionally on the basis of the delivered cost of Canadian imports relative to competing supply sources. Information on the prices and quantities of these alternative gas supplies helps provide a thorough understanding of the export market forecast. This feature is utilized below to explain the export forecast for the Pacific region.

Figures 7.8 and 7.9 present the quantities and prices of competing supply sources in the Pacific region. Although Canadian exports to the region increase until 1990, they are gradually displaced over time because of increased sales of gas produced in the Pacific and

Figure 7.8

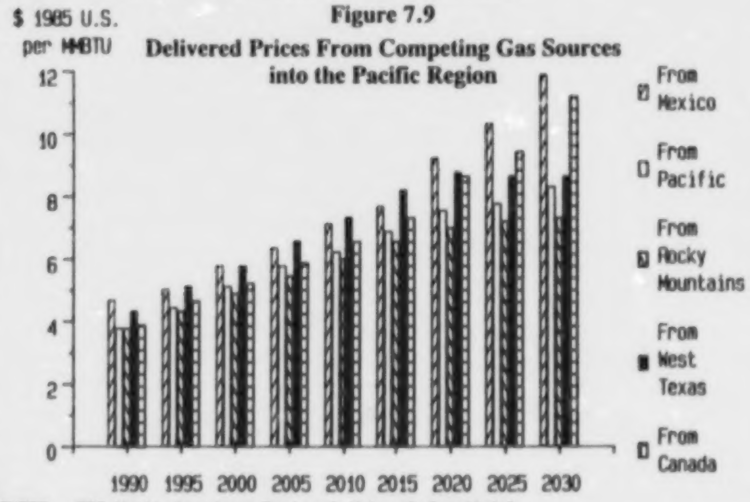
Delivered Quantities From Competing Gas Sources into the Pacific Region



SOURCE: GRI North American Regional Natural Gas Model.

Figure 7.9

Delivered Prices From Competing Gas Sources into the Pacific Region



SOURCE: GRI North American Regional Natural Gas Model.

Rocky Mountain supply regions. Figure 7.9 illustrates that the primary reason for the expansion in market share is the lower delivered cost of gas produced from these sources relative to Canadian gas. As noted above, Canadian gas is displaced to the Northeastern market where additional supplies are required to offset declining production from those U.S. supply regions having pipeline access to the region.

It should be noted that the existing pipeline capacity for Canadian gas into the Pacific region--about 735 Bcfs per year through Kingsgate and Huntingdon--might dampen this shift because of existing long-term contracts (and renewals) and the risks associated with a large expansion of pipeline capacity into the Mid Atlantic/New England region. In addition, a crucial assumption in this analysis is that a pipeline will eventually be constructed to deliver Rocky Mountain gas into the Pacific region.[3] The possibility of a pipeline to deliver Rocky Mountain gas directly to the East North Central or New England/ Mid Atlantic region was not (yet) accounted for. Such a facility may prove to be viable in the medium term (10 to 15 years) and could provide a limit on Canadian gas exports to the Northeastern states. Under this scenario, the Pacific region would likely continue to be the major importer of Canadian gas over the forecast horizon. (Information on competing supply sources for the other three importing U.S. demand regions appears in Appendix G.)

7.3.1.3 Forecast of U.S. Production Capability

Gas production in the U.S. is forecast to undergo some fairly pronounced regional and technological shifts over the forecast horizon. Tables 7.2 and 7.3 summarize the forecast of U.S. gas production by region and technology. Examination of these tables reveals a number of important trends:

- U.S. Lower-48 onshore and offshore production is expected to decline throughout the forecast;
- the supply regions in which this trend is most pronounced are the Anadarko, West Texas, and Gulf Coast regions;
- substantially increased production from the Rocky Mountain region and "deep" Lower-48 resources partially offset this decline;
- North Alaskan gas is required in significant quantities--exceeding 1 quad annually--after the year 2010; and

TABLE 7.2
U.S. PRODUCTION OF NATURAL GAS BY REGION
(quadrillion Btus)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.36	0.52	0.65	0.67	0.66	0.64	0.60	0.54	0.42	0.30
Rocky Mountains	1.50	1.85	2.29	2.60	2.67	2.63	2.79	3.16	3.27	3.37
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	2.13	3.90
Anadarko	2.83	2.46	2.29	2.30	2.27	1.95	1.87	1.59	1.15	0.71
West Texas	1.48	1.36	1.31	1.37	1.27	1.16	1.31	2.20	3.01	3.90
Gulf Coast	9.41	8.20	7.74	7.78	7.40	6.71	6.21	5.19	3.67	2.14
Midwest	0.12	0.12	0.11	0.11	0.10	0.08	0.09	0.15	0.29	0.43
Appalachian	0.43	0.96	1.35	1.63	1.45	1.23	0.99	1.08	1.17	1.25
Total Lower 48	16.13	15.48	15.76	16.45	15.82	14.36	13.39	14.19	15.10	16.00
South Alaska	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.22	0.18	0.15
North Alaska	0.00	0.00	0.00	0.00	0.00	1.23	1.23	1.37	1.40	1.43
Total U.S.	16.36	15.71	15.99	16.68	16.05	15.83	15.83	15.78	16.67	17.58

SOURCE: North American Regional Natural Gas Model.

TABLE 7.3
U.S. PRODUCTION OF NATURAL GAS BY TECHNOLOGY
(quadrillion Btus)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.86	9.45	9.38	9.33	8.49	7.29	6.31	5.24	3.81	2.39
Lower 48 Offshore	4.71	4.49	4.62	4.80	4.47	4.00	3.59	2.81	1.99	1.16
Lower 48 Deep	1.56	1.54	1.76	2.31	2.86	3.08	3.49	3.48	2.47	1.82
Alaskan	0.23	0.23	0.23	0.23	0.23	1.47	1.57	1.60	1.57	1.58
Lurgi Coal Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.47	2.67	6.64	10.61
Total	16.36	15.71	15.99	16.68	16.05	15.83	14.95	15.78	16.67	17.58

SOURCE: North American Regional Natural Gas Model.

- in order to offset declining domestic production and Canadian imports, and in the absence of significant technological advance in "tight sands" production, the U.S. must increasingly rely on coal gasification technology to meet domestic gas requirements towards the end of the forecast time horizon. Note that gas from other nonconventional sources such as Devionian shales, coal bed methane, and improved secondary gas recovery techniques which were not incorporated into the modelling framework could considerably reduce this dependency on coal gasification.

Average U.S. wellhead prices by supply region are presented in Table 7.4. It is interesting to note that these prices generally bracket those forecast for the Canadian supply regions. However, Canadian wellhead prices are on average lower than in the U.S., reflecting the higher transportation costs that must be paid to deliver Canadian gas and the correspondingly lower netbacks that Canadian producers receive. As before, the projected long-run equilibrium price level is considerably higher than the prices being observed today.

7.3.2 Sensitivity and Policy Case Results

In order to portray the essential impacts of the sensitivity and policy cases relative to the reference case, three key statistics are presented in this section:

- average domestic burner-tip prices,
- average domestic wellhead prices, and
- Total natural gas exports to the U.S.

Because it is the impact of these cases relative to the reference case that is of interest, reference case results are included in all tables and figures for purposes of comparison.

7.3.2.1 Sensitivity Case Results

The impact of the sensitivity cases on average burner-tip prices in Ontario appears in Figure 7.10. The impact that these cases have on the average Canadian wellhead price is shown in Figure 7.11. Figure 7.12 compares the level of natural gas exports to the U.S. under the different cases.

TABLE 7.4
AVERAGE U.S. WELLHEAD PRICE BY REGION
($1985 U.S. per MMBtu)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast		3.15	3.74	4.39	4.96	5.49	6.13	6.71	7.01	7.58
Rocky Mountains		2.86	3.41	3.94	4.49	5.01	5.53	5.99	6.09	6.20
Northern Great Plains		0.00	0.00	0.00	0.00	0.00	0.00	7.29	6.41	6.12
Anadarko		3.41	4.08	4.72	5.40	6.09	6.91	7.62	7.91	8.49
West Texas		3.45	4.11	4.76	5.49	6.26	7.05	7.24	7.07	7.04
Gulf Coast		3.49	4.16	4.83	5.54	6.31	7.15	7.95	8.15	8.67
Midwest		4.24	5.06	5.79	6.57	7.48	8.41	8.81	8.85	8.69
Appalachian		3.54	4.27	5.00	5.87	6.76	7.80	8.52	8.51	8.56
Average		3.40	4.03	4.67	5.35	6.06	7.03	7.40	7.23	7.09

SOURCE: North American Regional Natural Gas Model.

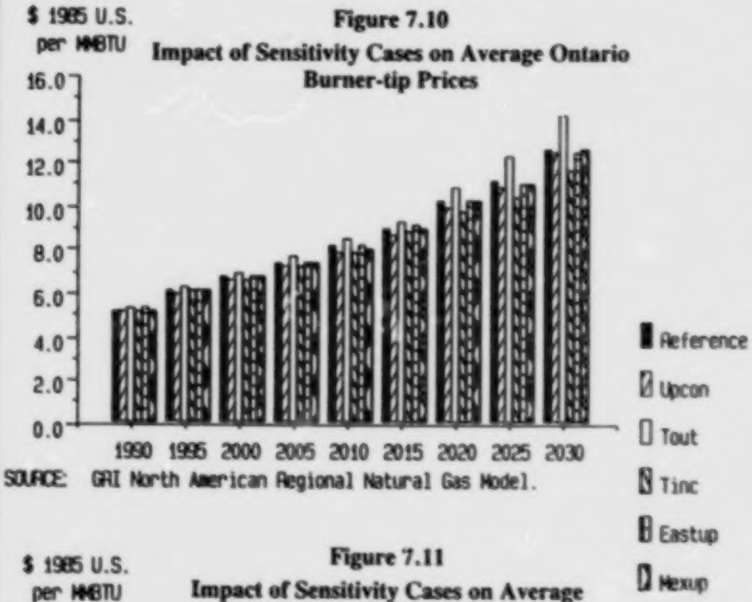


Figure 7.10

Impact of Sensitivity Cases on Average Ontario Burner-tip Prices

SOURCE: GRI North American Regional Natural Gas Model.

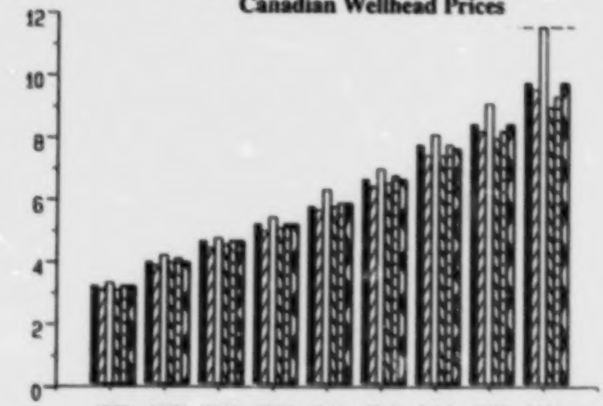
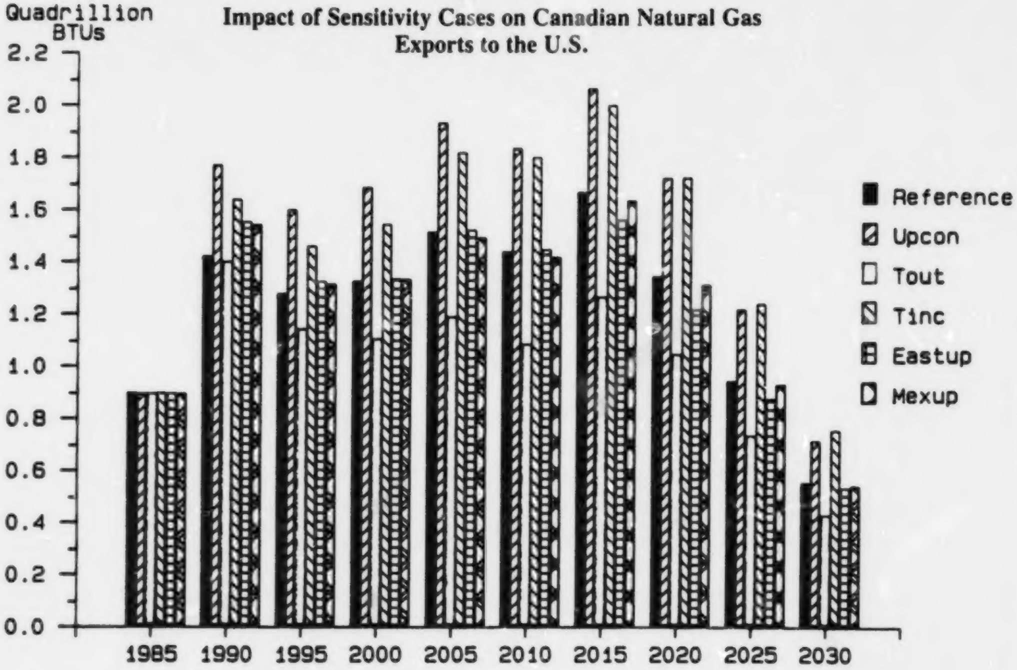


Figure 7.11

Impact of Sensitivity Cases on Average Canadian Wellhead Prices

SOURCE: GRI North American Regional Natural Gas Model.

Figure 7.12
Impact of Sensitivity Cases on Canadian Natural Gas Exports to the U.S.



SOURCE: GRI North American Regional Natural Gas Model.

As illustrated, the reference case price and export forecasts are fairly robust to the changes incorporated in the sensitivity cases. Note, however, the following key results:

- In the two cases where a larger Canadian resource base is assumed (UPCON and TINC), wellhead and burner-tip prices are depressed in every region of the country relative to the reference case. Moreover, export volumes are greater in every forecast period.
- The longer-term impacts of TINC on prices and exports contrast with the near-term impacts of UPCON. Although both assume larger Canadian gas resources, UPCON assumes that these quantities are of lower cost than TINC. As a result, in the near term prices are lower and exports are higher, reflecting the fact that this lower cost gas is more competitive in the U.S. This increased competitiveness is delayed in TINC until prices have increased enough to sustain higher cost production; then, the larger quantities of this gas act as a damper against price increases and displace higher cost Lower-48 gas in the U.S. later in the forecast period.
- In TOUT, where tight gas production is assumed to be completely uneconomical, the reverse is true--prices are higher and exports are lower in every period relative to the base case.
- Increased Eastern Offshore supply costs (modelled in EASTUP) have relatively little impact on the reference case results. This is because the only region in which East Coast gas competes extensively with domestic supplies is the Mid Atlantic/New England region. This is in sharp contrast to the above cases where changes in Alberta resources impact significantly on prices throughout Canada.
- To illustrate this difference, cheaper Alberta gas has a significant dampening effect on burner-tip prices in all markets sourcing Alberta gas. These lower prices are fed back directly to the wellheads of all competing sources, both domestic and U.S. Higher cost East Coast gas does result in lower exports from this region to the Mid Atlantic/New England region.
- The assumption of increased Mexican exports has only a marginal effect on the level of Canadian gas exports. Mexican exports will tend to displace higher cost Lower-48 production before Canadian gas.

One would expect that these sensitivity cases would also impact on the timing and sourcing of frontier production from Northern Canada and the Eastern Offshore region. As Tables 7.5 and 7.6 illustrate, it is not the timing so much as the initial production levels that are affected. It should be noted that since the model results are presented in 5-year increments, initial production from these sources is likely to differ on a yearly basis. Some important trends are, however, evident:

- If Canadian conventional or tight sands gas resources are larger than assumed in the reference case, the initial quantities of frontier gas required are diminished due to the high delivered cost of gas from these regions relative to conventional sources. (The reverse is also true.)
- By 2020, significant quantities of Northern gas are required in all cases. In fact, although the quantity of Northern gas is constrained to 1600 MMCFD (0.600 quads annually, the capacity of an expanded Polar Gas pipeline), estimated production slightly exceeds this level from 2020 to 2030. This suggests that future economic forces might be strong enough to warrant a larger capacity pipeline. Additional quantities of Northern gas could displace more expensive tight sands and conventional gas by this time.
- Eastern offshore production is relatively more insensitive to the changes incorporated within the sensitivity cases than Northern production. This is because Eastern Offshore gas does not compete extensively with Alberta and B.C. gas. However, production is sensitive to changes in the cost of Eastern gas as higher costs reduce demand for this gas in the Mid Atlantic/New England region.

7.3.2.2 Policy Case Results

While the reference case results may be quite insensitive to the changes incorporated in the sensitivity cases, this is definitely not true for the possible policy alternatives we have examined. Each of the policy cases introduces severe distortionary effects which significantly impact on the equilibrium solution to the model. As a result, prices and quantities calculated in these cases differ significantly from the reference case results. These differences are presented in the same format used in the discussion of the sensitivity cases.

Policy case ROYAL examines the long-term impact of increased royalties on Canadian conventional gas production. In a simple static economy with only one supply source, the impact of imposing a royalty tax on production is to shift the gas supply curve up by the amount of the royalty. At this higher price, less of the gas is demanded at the

TABLE 7.5

IMPACT OF SENSITIVITY CASES ON THE TIMING OF FRONTIER PRODUCTION: NORTHERN CANADA

quadrillion Btus)

Initial Year of Production	REFCASE	UPCON	TOUT	TINC	EASTUP	MEXUP
Production						
2010	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.33	0.22	0.56	0.23	0.42	0.32
2020	0.66	0.65	0.66	0.65	0.66	0.66
2025	0.67	0.67	0.69	0.66	0.67	0.67
2030	0.69	0.69	0.72	0.68	0.69	0.69

SOURCE: North American Regional Natural Gas Model.

TABLE 7.6

IMPACT OF SENSITIVITY CASES ON THE TIMING OF FRONTIER PRODUCTION: EASTERN CANADA OFFSHORE

(quadrillion Btus)

Initial Year of Production	REFCASE	UPCON	TOUT	TINC	EASTUP	MEXUP
Production						
2010	0.00	0.00	0.00	0.00	0.22	0.00
2015	0.59	0.49	0.40	0.77	0.48	0.58
2020	0.81	0.84	0.87	0.76	0.52	0.82
2025	0.61	0.64	0.67	0.58	0.56	0.62
2030	0.42	0.43	0.47	0.39	0.69	0.42

SOURCE: North American Regional Natural Gas Model.

burner-tip. However, in a complex dynamic economy consisting of multiple supply sources, consumers will rearrange their supply portfolio to minimize the costs of the royalty tax. The resultant burner-tip price is lower than in the simple static case and, in addition, the resultant demand for gas on which the royalty was imposed is less, to the extent that it is displaced by cheaper alternative supplies.

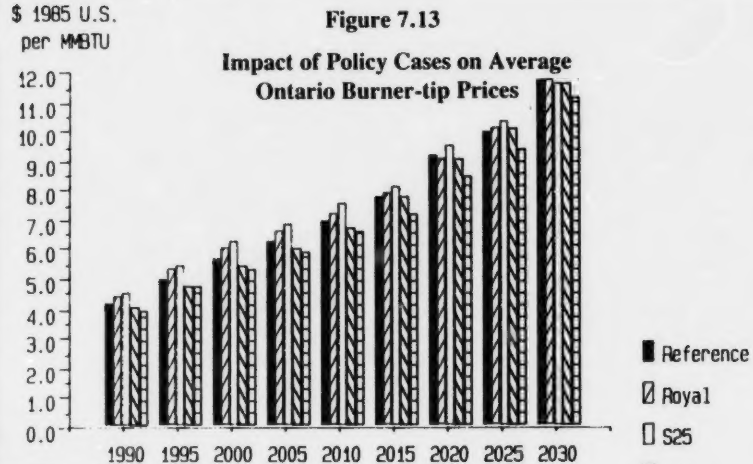
As illustrated in Figures 7.13 through 7.15, the imposition of a 16 percent effective royalty rate on wellhead and burner-tip prices has the following effects. The average wellhead price falls an average of 16 percent while burner-tip prices increase an average of 5 percent.[4] The increases in the delivered cost of gas into the U.S. cause some Canadian gas to be displaced by cheaper U.S. gas in the early time periods. Exports return to near reference case levels later in the time horizon, despite higher Canadian prices, to replace the Lower-48 production that had earlier displaced Canadian exports.

As discussed in Chapters 3 and 5, Canadian producers have operated under some kind of export surplus rule for two decades. For most of this period prices were also regulated. The policy cases 10SURP and 25SURP attempt to assess the impact of imposing a surplus rule in an economic environment in which wellhead prices are deregulated. 10SURP was essentially developed as a completely free market scenario in which natural gas reserves are produced at or near full capacity.

As Figures 7.13 through 7.15 illustrate, the impact of the two cases on prices is very pronounced. Under the 25-year test, domestic burner-tip prices are on average 8 percent greater than in the reference case. The prices paid by domestic consumers in 10SURP are on average 5 percent less than in the reference case. The explanation behind these price effects is based on the carrying costs associated with the reserve level. With a high reserve requirement, gas producers are required to discover and carry substantial inventory before any sales can be made. Referring to the discussion in Section 3.2 on the ratio of above-ground to in-ground costs, when production rates are restricted to low levels, the price required at the wellhead is higher than the level otherwise required in order to recover the up-front sunk capital costs. In a deregulated market environment that is not characterized by the excess capacity of today's market, producers will pass these higher wellhead costs and the financial charges associated with holding a reserves inventory on to the consumer.[5] Similarly, if

Figure 7.13

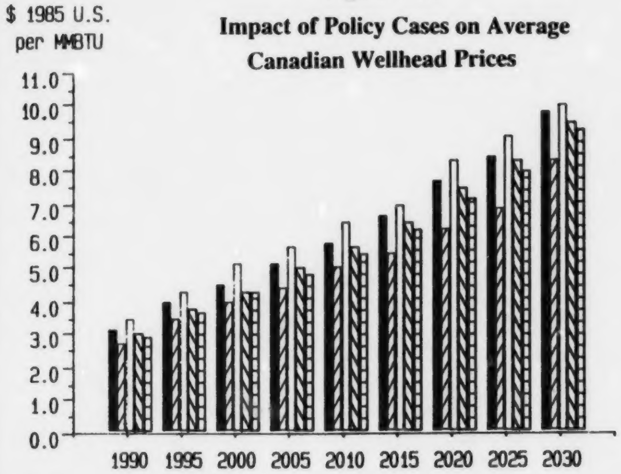
Impact of Policy Cases on Average Ontario Burner-tip Prices



SOURCE: GRI North American Regional Natural Gas Model.

Figure 7.14

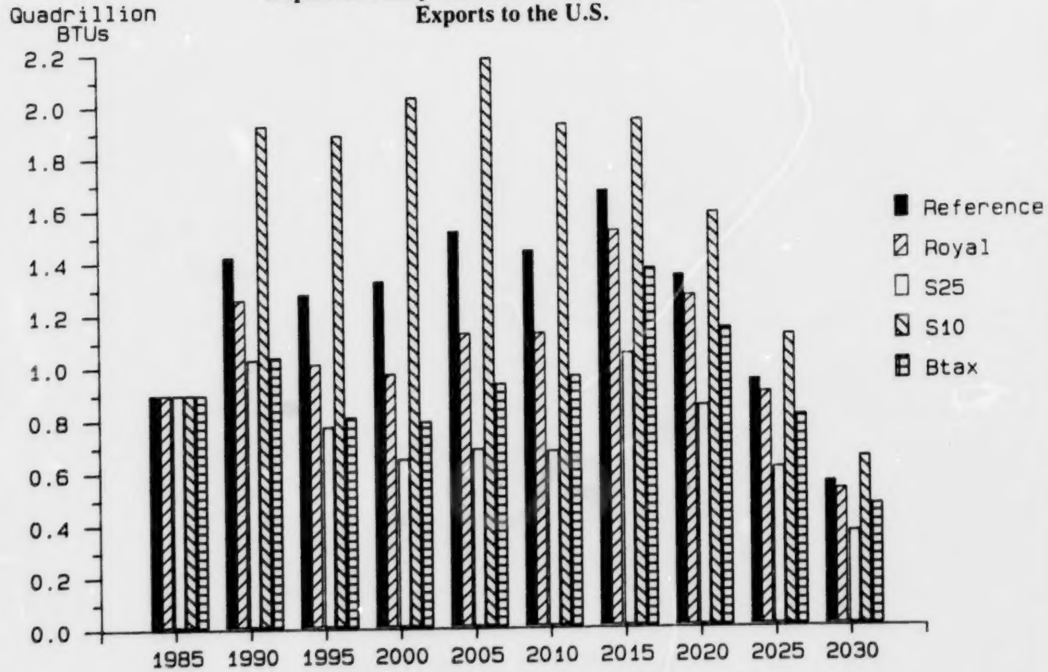
Impact of Policy Cases on Average Canadian Wellhead Prices



SOURCE: GRI North American Regional Natural Gas Model.

Figure 7.15

Impact of Policy Cases on Canadian Natural Gas Exports to the U.S.



SOURCE: GRI North American Regional Natural Gas Model.

production is unconstrained, lower wellhead costs are passed on to the consumer in the form of lower burner-tip prices.

The impact that the surplus test has on natural gas exports is also very significant as illustrated in Figure 7.15. Under the 25-year test, the resultant high prices severely restrict the competitiveness of Canadian gas in the U.S. Exports are on average 60 percent lower than in the reference case. Under a 10-year test, Canadian producers realize substantially increased export sales as lower delivered prices allow them to displace a large amount of more expensive Lower 48 production.

An alternative method of restricting natural gas exports is to impose a border tax on all such sales. In BTAX we have tried to capture the possible impacts on prices and quantities that a $0.75 per MMBtu export tax might have. A border tax may be thought of as a royalty on natural gas production destined for the export market in that it depresses wellhead prices while increasing the cost of gas into the U.S. Export levels thus decline to the extent that increased prices have rendered exports uncompetitive, about 55 percent in this case. A rather perverse effect of imposing a border tax when wellhead prices are deregulated is that domestic burner-tip prices will also decline because, in a competitive gas market, the average netback at the wellhead is roughly equated from all sales. The impact that such a mechanism has on producer revenue is thus substantial--not only do export sales decline significantly but the price received for domestic sales also declines.

Because the different policy cases have such a strong impact on domestic natural gas production, they also impact significantly on the timing of frontier production, as illustrated in Tables 7.7 and 7.8. As the volume effects of imposing a 25-year surplus rule are so strong, production from Northern Canada does not become viable until 2020 and is sharply reduced relative to the reference case. The timing of production from the Eastern Canadian Offshore region is unaffected although the volume of production is similarly reduced. The accelerated production under a 10-year surplus rule brings the viability of Northern Canadian production forward to 2010. It also increases the demand for Eastern Offshore gas considerably. The other cases, ROYAL and BTAX, impact less significantly on frontier production although in BTAX production from Northern Canada in 2015 is significantly lower than in the reference case.

TABLE 7.7

IMPACT OF POLICY CASES ON THE TIMING OF FRONTIER PRODUCTION: NORTHERN CANADA (quadrillion Btus)

Initial Year of Production 2015	REFCASE	ROYAL	25SURP	10SURP	BTAX
Production					
2010	0.00	0.00	0.00	0.20	0.00
2015	0.33	0.37	0.00	0.66	0.16
2020	0.66	0.65	0.18	0.68	0.65
2025	0.67	0.67	0.42	0.70	0.67
2030	0.69	0.69	0.65	0.72	0.69

SOURCE: North American Regional Natural Gas Model.

TABLE 7.8

IMPACT OF POLICY CASES ON THE TIMING OF FRONTIER PRODUCTION: EASTERN CANADA OFFSHORE (quadrillion Btus)

Initial Year of Production 2015	REFCASE	ROYAL	25SURP	10SURP	BTAX
Production					
2010	0.00	0.00	0.00	0.00	0.00
2015	0.59	0.59	0.30	0.82	0.68
2020	0.81	0.79	0.57	1.04	0.76
2025	0.61	0.60	0.47	0.72	0.58
2030	0.42	0.41	0.38	0.40	0.40

SOURCE: North American Regional Natural Gas Model.

In order to compare the impacts of the four policy cases, we have estimated the costs and benefits associated with each relative to the reference case over the models' 45-year time horizon. Two measurements of these costs and benefits are presented. The first, net user cost, is essentially a measure of the profit that is calculated to accrue to Canadian producers and the owners of the resources. This is simply calculated as the difference between total revenue and total cost, discounted to yield an estimate of the net present value of user costs. The second measure, total benefits, is calculated as the sum of producer and consumer benefits relative to the reference case. Producer benefits are calculated as the difference between net user costs estimated in the reference and policy cases while consumer benefits are calculated as the difference in the consumption bill paid by Canadian consumers in the two cases. To account for differences in benefit and cost streams over time, three real discount rates are used to estimate net present values: 5, 10, and 15 percent.

The results of the cost-benefit analysis appear in Tables 7.9 and 7.10. As shown in the tables, the net present value of net user costs and total benefits is very sensitive to the discount rate used, especially in the two cases examining the impact of the surplus rule. Of the four policy cases, BTAX is clearly the most unfavourable towards producers. The net present value of net user costs is the lowest at all three discount rates and, except for SURP10 at a 5 percent discount rate, total benefits relative to the base case are also the lowest.

An interesting result of the analysis is that the imposition of higher royalties increases the net present value of net user costs relative to the reference case at all three discount rates, due to lower production rates over time and the corresponding deferral in the production of higher cost reserves relative to the base case. However, because of the resultant higher domestic burner-tip prices, total benefits relative to the reference case are only positive at a 5 percent discount rate, reflecting the fact that price increases relative to the reference case occur towards the beginning of the modelling horizon.

The results of the two surplus test cases contrast sharply. Associated with the higher production volumes under the 10-year surplus test are much higher production costs. Because depletion of domestic gas resources is accelerated in the early time periods, higher cost supplies must be produced more intensively towards the end of the modelling horizon. As a result, the calculation of the net present

TABLE 7.9
IMPACT OF POLICY CASES ON NET USER COSTS RELATIVE TO THE REFERENCE CASE
($1985 billion U.S.)

Discount Rate	REFCASE	ROYAL	25SURP	10SURP	BTAX
5	188.2	203.8	220.3	185.9	176.5
10	96.3	100.5	105.3	103.8	89.4
15	58.2	60.0	62.1	65.4	54.2

SOURCE: Canadian Energy Research Institute.

TABLE 7.10
TOTAL BENEFITS OF POLICY CASES RELATIVE TO THE REFERENCE CASE
($1985 billion U.S.)

Discount Rate	ROYAL	25SURP	10SURP	BTAX
Producer Benefits				
5	15.6	32.1	-2.3	-11.6
10	4.2	8.9	8.6	-6.9
15	1.8	3.9	7.2	-4.0
Consumer Benefits				
5	-13.30	-15.10	-15.60	4.90
10	-6.10	-8.70	-7.30	0.80
15	-3.50	-5.70	-4.40	0.10
Total Benefits				
5	2.29	17.00	-17.80	-6.70
10	-1.90	0.20	0.30	-6.10
15	-1.71	-1.80	2.80	-3.90

SOURCE: Canadian Energy Research Institute.

value of user costs is very sensitive to the discount rate employed. As shown in Table 7.9, at a 5 percent discount rate the present value of net user costs is slightly lower than in the reference case and considerably lower than in 25SURP. However, as the discount rate is increased, the present value of net user costs in 10SURP becomes greater than in either the reference case or 25SURP due to the decreased contribution of higher production costs in the future to the present value calculation.

A similar trend is evident in the calculation of total benefits. The major difference is that total benefits estimated at a 10 percent rate of discount exceed, slightly, those estimated in both the reference case and 25SURP. This differential widens at higher discount rates. In the calculation of total benefits, lower burner-tip prices in early time periods under the 10-year surplus rule somewhat offset higher production costs in the latter periods. However, because these lower prices stimulate domestic consumption, this impact is lessened to some extent.

The sensitivity of the above results to changes in the discount rate evokes the question, "What is the appropriate social discount rate?" While we will not discuss this question in detail, two key points are pertinent:[6]

- the appropriate rate of discount is greater than zero; and
- the private rate of discount is generally greater than the social rate of discount.

From a government perspective, it is the social discount rate that is applicable in valuing the costs and benefits of alternative policies. It has been argued that there are sound reasons why a 10 percent social discount rate for Canada is too high and that 7 percent is more appropriate for cost benefit analysis.[7] If this is the case, there is only a marginal difference in the total benefits accruing under the different surplus test cases and the reference case. At the higher discount rates used in industry, the higher production levels possible under 10SURP become increasingly attractive. It should be noted that differences between the two surplus test cases are very sensitive to assumptions regarding the cost of undiscovered reserves.

7.4 Summary

The GRI North American Regional Natural Gas Model provides a consistent representation of the natural gas supply, demand and transportation sectors. The supply of natural gas is allocated to demand at a market clearing price through a complex network which interconnects these sectors and simultaneously balances the large number of supplies and demands over time. This solution results in a number of market clearing prices, each specifying the economics and quantities of natural gas for a particular region at a given point in time. Submodels incorporate the engineering, geological, economic and behavioral logic that is needed to accurately characterize the North American natural gas industry.

The use of such a powerful model has allowed CERI to formulate a long-term forecast of natural gas prices and quantity flows that is consistent with the movement towards a deregulated natural gas market in both Canada and the U.S. A great deal of research effort and expense has been devoted by the Gas Research Institute towards the data input describing the U.S. gas industry. This representation of the U.S. considerably enhances our forecast of export volumes and prices. The modelling framework also allows us to address the impact that changes in key parameters such as the cost and magnitude of undiscovered resources in Canada have on the reference case forecast. In addition, the scope of the model allows for a consistent appraisal of the costs and benefits and the long-term impacts that various policy alternatives might have on the future evolution of the natural gas industry.

A number of important developments are highlighted by the results of this analysis. We wish to emphasize the following key implications:

- Prices will be considerably higher than today's levels once the current surplus in productive capacity in both Canada and the U.S. has dissipated and demand and supply are roughly equated.
- The long-term equilibrium level of gas prices has the potential to exceed the cost of oil substitutes in the industrial sector in the near to medium term. This points to the importance of world oil prices as a major determinant of natural gas prices and the potential for significant load losses if in fact natural gas prices do periodically exceed the cost of oil substitutes. Such a

situation may be averted in a deregulated market as those large industrial users having the capability of switching fairly quickly to oil could contract directly with producers and negotiate a flexible price that maintains the competitiveness of gas relative to oil. This, of course, is dependent on whether or not there are adequate gas supplies available at discount prices.

- Under the scenario of deregulated wellhead prices in Canada and the U.S., Canadian prices will, to a large extent, be determined by the netbacks which producers receive from export sales since netbacks received by a producer from all sales will be approximately equal in a competitive market.

- The future of Canadian gas trade with the U.S. is extremely promising; considerable increases in export volumes and prices are forecast.

- The Mid Atlantic/New England region is identified as the major long-term growth market for Canadian export sales because of declining production in the Anadarko, Gulf Coast, and West Texas supply regions and limited pipeline access to other Lower-48 supply regions.

- Sales into the East North Central region are fairly constant over time while, except for short-term growth, exports to the Pacific and West North Central regions gradually decline over time due to competition from gas produced in the Rocky Mountain supply region.

- Significant additions in pipeline capacity, possibly in excess of the current Iroquois proposal, would be required to transport forecast volumes of Alberta gas to the Mid Atlantic/New England region.

- In order to meet forecast export volumes and domestic demand, gas-directed drilling activity will have to increase dramatically once the surplus in productive capacity declines.

- There is considerable uncertainty regarding the costs and feasibility of tight sands gas production in Alberta's deep basin. The fairly conservative estimates of potential reserves and costs utilized in this study suggest that tight sands production is likely to become an increasingly important facet of the Canadian gas industry. Moreover, the location of these reserves relative to the existing transportation network allows for higher wellhead prices and increases the viability of these reserves vis-a-vis the frontier regions.

- Production from frontier reserves in Northern Canada and the Eastern Offshore region will not be required until after 2010 if conventional and tight sands resources are utilized efficiently. This result is a combination of the relatively high cost of developing reserves in these regions and the large capital costs required for the construction of the requisite transportation facilities.

- Alternative surplus tests are quite neutral with respect to the total cost and benefits associated with each; however, the distribution of these costs and benefits contrasts sharply. Under a 25-year test, consumers will pay higher prices but lower production levels will defer the production of higher cost gas. In the 10-year test, consumers will pay lower prices but much higher production levels result in the accelerated production of higher cost gas. Thus, under a more relaxed surplus test, it is the net present value of the rent received by the resource owners and gas producers that decreases and the benefits for consumers that increase.

- An export tax on natural gas is the most distortive and potentially harmful method of protecting Canadian consumers. Although Canadian consumers pay less for gas, this is more than offset by the decline in revenue received by the resource owners and gas producers.

- Increasing royalty rates appears to be a fairly efficient method of increasing the net present value of rent collected by the resource owner. Production is depressed due to lower wellhead and higher burner-tip prices, thereby deferring production of higher cost reserves. However, the benefits to the producting sector are in general offset by higher prices to consumers.

Footnotes

[1] We note here that under the reference case, the resource owner is assumed to capture the scarcity rent component of price which, under the assumption of perfect foresight, could theoretically be accomplished through the lease bidding process and a tax on corporate profits. Realistically, the resource owner tries to capture available rents through a combination of the lease bidding process and the imposition of royalties and taxes. Our reference case assumes that royalties are implicity captured in the scarcity rent. Because royalties distort the producer's decision by shifting the supply curve, the royalty sensitivity case seeks to explicitly quantify the impact of royalties on the market place.

[2] The residual fuel oil prices presented are GRI's forecast of the average retail price of residual fuel in the U.S. and are provided in Chapter 4, Table 4.2. It should be noted that given the same crude oil price forecast, Canadian residual fuel oil prices are likely to vary because of different refinery margins, differences in refinery production slates, etc.

[3] Both El Paso and Transwestern have proposals before FERC to increase their capacity to move Rocky Mountain gas to California. In addition, the California Energy Commission has shown that a direct pipeline from the Rockies to California would be economically viable. Although the Commission does see an increasing reliance on Rocky Mountain gas over time, they are extremely optimistic regarding the future availability of gas from the West Texas region. They also assume that an average of 420 Bcfs will be available annually from Canadian exporters till 2007 (see Calfornia Energy Commission, Biennial Fuels Report (Final Draft), November 1987, pp. 2-1 and 2-8).

[4] Note that the wellhead price still includes a scarcity rent component which is now smaller because royalties have been deducted from it. But the total revenue (rent plus royalties) that could be extracted under perfect foresight is now smaller because demand has decreased.

[5] Note that under a 25-year export surplus test, the Canadian gas industry is essentially regulated. A great concern of producers that has been expressed in the past is that in such an environment, they are unable to pass higher costs along to consumers.

[6] A more detailed discussion of the appropriate social discount rate and related issues is contained in D. F. Burgess, "Some Comments on the Theory and Measurement of the Social Discount Rate for Canada" (June 1983), pp. 49-55.

[7] Ibid., pp. 53-54.

Chapter 8

CONCLUSIONS, RECOMMENDATIONS, AND AREAS FOR FUTURE RESEARCH

8.1 Summary and Conclusions

The unprecedented decline in oil and gas prices over the last few years, together with natural gas deregulation and the increased complexity of operating in an altered marketplace, has focussed attention on the short-term price and sales trends in the North American gas industry. On the supply side, survival has emerged as the dominant concern, particularly for small independent producers who are desperate for cash flow to service their debt obligations. Excess gas supplies have driven prices in the Canadian direct sales and U.S. spot markets below replacement costs. Consumers have taken advantage of the potential savings these markets offer by leaving pipeline system sales (where possible) to enter into shorter-term contracts, forsaking the traditional priority of security of supply. In this new environment, producers and consumers alike are primarily concerned with the price each will face in the next year or, in many instances, the next month.

The danger of such myopia is that the long-term realities of the industry and future opportunities will become obscured. Although there are a number of studies and reports available that address long-term issues and trends, they generally focus on either the U.S. market or the Canadian market and ignore the impact that the emerging continental gas market will have on regional trade flows and prices in Canada.[1] This study is intended to fill a perceived need for a long-term appraisal of the future evolution of the Canadian gas industry within a larger, unified North American gas market. Identifying long-term shifts in gas consumption patterns, trade flows and production sourcing is crucial for effective long-range planning in an industry where long lead-times between discovery and development of new reserves and the addition of pipeline capacity are an immutable fact.

The issues that face the Canadian gas industry today include the identification of future export markets--both locationally and volumetrically--and concomitantly, the need for new or expanded pipeline facilities to serve new or incremental markets. Some fears have been expressed that the removal of the export surplus rule and the Free Trade Agreement will result in Canadians losing effective control over this country's natural gas resources because the U.S. market will dominate the Canadian market.[2] As one version of the argument goes, a depleting resource base in the U.S. will result in rising prices. Canadian exports will increase dramatically and domestic consumers will be left paying higher prices and thereby face the prospect of having to consume higher cost gas sooner than they would if access to the U.S. market had remained controlled.[3] Concerns have also been expressed about the inadequacy of current low prices and an uncertain future to provide producers with sufficient incentive to invest in the exploration and development activity necessary to maintain production to meet future demand (especially in the U.S.).[4]

No single response to the above questions and issues can claim to be definitive, given the tremendous complexity and vast scope of the North American gas industry. However, the quality and validity of any answer will depend on the underlying economic logic and the extent to which the essential long-term features of the industry are accounted for. In this study, we present a long-term analysis of the North American natural gas industry based upon the application of a comprehensive modelling methodology which is particularly well suited to addressing the above issues.

The North American Regional Natural Gas Model provides a consistent multi-regional representation of natural gas supply, demand and transportation. The supply of natural gas is allocated to demand at a market clearing price through a complex network which interconnects these sectors according to the transportation system and simultaneously balances the large number of supplies and demands over time. This solution results in a number of market clearing prices, each specifying the economics and quantities of natural gas for a particular region at a given point in time.

The use of such a powerful model has allowed the Canadian Energy Research Institute to formulate a long-term forecast of natural gas prices and quantity flows that is consistent with the movement towards a deregulated natural gas market in both Canada and the U.S. A great deal of research effort and expense has been devoted by the Gas Research Institute towards the data inputs describing the U.S. gas industry. This representation of the U.S. considerably enhances our forecast of export volumes. The modelling framework has also allowed us to address the impact that changes in key parameters, such as the cost and magnitude of undiscovered resources in Canada, may have on the reference case forecast. In addition, the scope of the model allows for a consistent appraisal of the cost and benefits and the long-term impacts that various policy alternatives might have on the future evolution of the natural gas industry.

As more fully outlined in previous chapters, this study has revealed a number of important long-term trends in future gas trade with the U.S., in future prices and in production sourcing, as well as several interesting policy implications. We summarize below, the key results and implications of this analysis.

8.1.1 Future Gas Trade With the U.S.

The long-term outlook for Canadian gas trade with the U.S. is very promising. Our analysis indicates that an optimal strategy for Canadian producers involves lower export levels than those currently licensed by the NEB, although they are significantly higher than today's actual levels. The reference case forecast is presented in Figure 8.1 by importing U.S. regions. As illustrated, export levels are forecast to increase over time, from 1.4 quads in 1990 to 1.7 in 2015, to replace an inevitable decline in U.S. production.

If Canadian gas supplies are larger than assumed in the reference case, or if production rates approach those in the U.S., considerably greater export levels would be possible. In the former case, larger gas supplies make it profitable for Canadian producers to reduce prices in the near term and thus gain a larger share of the U.S. market. Similarily, in the latter case higher production rates reduce the cost recovery period for capital investment and allow for a corresponding price reduction and increase in market share. If production rates are constrained as in the case of the 25-year surplus test, a higher wellhead price is required to recover up-front sunk capital investment. This seriously impedes the competitiveness of Canadian gas in U.S. markets.

Figure 8.2 illustrates the sensitivity of the reference case forecast to changes in assumed production rates. Under a 25-year surplus test, annual gas export volumes do not exceed 1 quad until 2015. Conversely, if reserves are produced at a 10-year reserves-to-production ratio, export levels that exceed 2 quads annually by the year 2000 are indicated as possible. Prices in the former case average 8 percent higher than in the reference case while higher production rates in the 10-year surplus test case allow for an average 4 percent reduction in prices relative to the reference case. It should be noted that it is the price of Canadian gas relative to U.S. gas, not the absolute magnitude of prices, that determines export levels. The price forecast is discussed in more detail below.

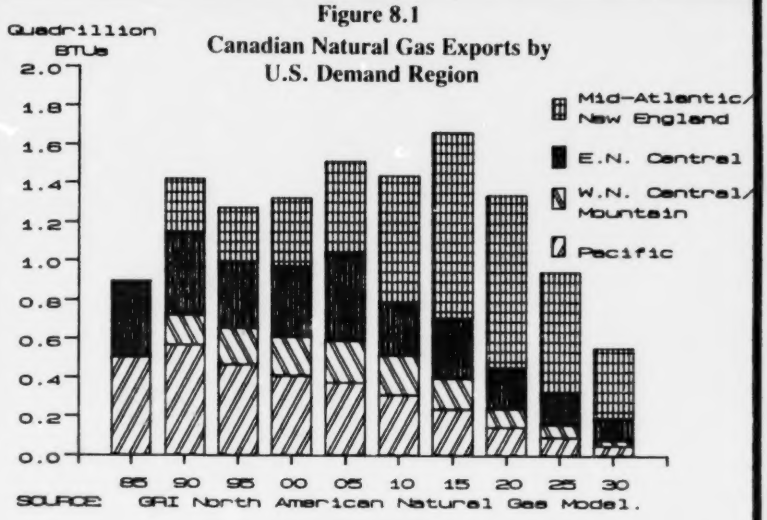
Given the level of exports associated with each of these price tracks, the implications are clear: U.S. demand for Canadian gas is very sensitive to changes in export prices. It follows that if a government policy such as a binding surplus test or export tax were imposed in a deregulated pricing environment, it would impact on wellhead prices and thus have a potentially serious impact on the level of Canadian gas exports to the U.S. A second implication is that Canadian gas exporters have little market power in the U.S. Canada will continue to supply only a small share of U.S. gas demand and the rather plentiful U.S. gas supplies serve as a nearly perfect substitute for Canadian gas.

Underlying this forecast of increased export levels is a fairly pronounced long-term shift in the relative importance of U.S. importing regions. The Pacific region (which includes California and the Pacific Northwest) is the major importer of Canadian gas, having purchased about 60 percent of Canadian gas exports in 1986, and is expected to continue to be Canada's largest export market for natural gas through to the end of this century. Canadian exports to this region are forecast to increase from just over 0.50 quads in 1985 to some 0.57 quads in 1990; however, exports are projected to slowly decline to 0.47 quads in 1995 and 0.38 quads in 2005. However, given the gas resource, demand, and transportation cost assumptions which form the framework of our modelling analysis, the Mid Atlantic/New England region is identified as the primary growth market for Canadian export sales. Demand for Canadian gas in this region has the potential to reach 0.25 quads in 1990 and increase to 0.48 quads per year by 2005 as illustrated in Figure 8.1.

This shift in trade flows results from the interaction of two fundamental determinants of long-term supply and demand shares in the U.S.: the regional distribution of undiscovered gas resources in the Lower-48 states, and the location of the existing pipeline network relative to those sources of supply. Currently the Anadarko, West

Figure 8.1

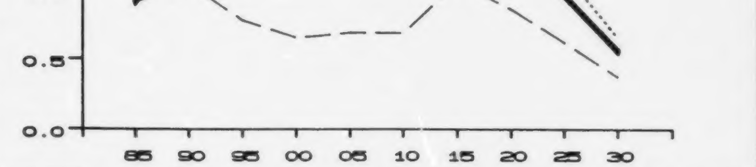
Canadian Natural Gas Exports by U.S. Demand Region



SOURCE: GRI North American Natural Gas Model.

Figure 8.2

Sensitivity of Canadian Exports to Changes in Annual Production Rates



SOURCE: GRI North American Regional Natural Gas Model, 1987.

Texas, and Gulf Coast supply basins are the primary sources of U.S. gas supplies, accounting for about 75 percent of production.[5] Because these regions have traditionally supplied a major share of U.S. gas production, the existing pipeline network in the Lower-48 states predominantly originates in this area.[6]

Our forecast indicates that gas production from these regions will decline slowly over time and that the resulting decline will be somewhat offset by increased production from the Rocky Mountain region. The proximity of the Rocky Mountain region and projected increases in production from indigenous Pacific reserves causes Canadian gas to be gradually displaced from the Pacific region. Increased demand for Canadian gas in the Mid Atlantic/New England region results from the combination of increased gas demand in the region, declining deliveries from the Anadarko, Gulf Coast, and West Texas regions, and limited access to other Lower-48 supplies.

These results merit close scrutiny given the structure of existing natural gas export facilities. Canada currently has the capacity to export about 1.8 quads annually to the U.S. However, the existing configuration of pipeline access is such that just over 50 percent of this capacity is dedicated to serving the Pacific region and about 40 percent to serving the West and East North Central regions. Direct Canadian pipeline access to the Mid Atlantic/New England region is severely constrained to an annual capacity of about 0.075 quads (including the Niagara border point and the Montreal/Portland pipeline).[7] Gas shipped through Emerson could potentially reach the Northeast market, either directly via a number of pipelines (although transportation costs are prohibitively high) or indirectly through displacement.[8]

The above analysis suggests that large additions in pipeline capacity to the Northeast U.S., possibly in excess of the Iroquois pipeline proposal, will soon be warranted if Canadian producers are to realize potential markets in this region. However, care must be taken to ensure that an optimal solution to this problem is chosen, and that existing facilities are utilized to the fullest possible extent in order to minimize the risk involved in new pipeline construction. Moreover, competition from other gas supplies and alternative fuels will require that the cost of transportation on new or expanded facilities be minimized and that any long-term contracts exhibit the flexibility required to meet future competition.

8.1.2 Future Natural Gas Prices

Excess gas supplies in Canada and the U.S. and volatile crude oil prices have combined to render any short-term forecast of gas prices highly uncertain. Gas prices in today's spot and direct sales markets are generally below replacement costs and alternative fuel prices due to the intense gas-on-gas competition caused by excess gas supplies and are thus intrinsically not sustainable. Once demand and supply are roughly equated, future prices in the emerging continental gas market will depend on the underlying cost of finding and developing future gas reserves, continued competition between different sources of gas supplies, and the price of competing fuels such as fuel oil, coal, and electricity.

In the model analysis, future natural gas prices are determined as the outcome of the actions of a group of profit-maximizing resource owners, each representing one of the major supply basins in North America and constrained to selling gas into those regions to which they have pipeline access. Resource owners decide on an optimal production path to meet a specified level of demand over time. Each of these resource owners has a different quantity of gas left to be discovered (as determined by the geology of the region) and faces different future costs of finding, developing, and producing this gas. The gas prices calculated by the model contain three components: a capital charge which is the price required to obtain a 10 percent real return on exploration and development investment; a charge to recover operating costs; and a scarcity rent which is the theoretically obtainable excess profits that the resource owner can collect because natural gas is a rising cost, depletable resource.[9] An alternative interpretation of the prices calculated by the model is that they represent the optimal value of natural gas as an exhaustible resource given the supply cost assumptions and future level of demand we have specified.

The resulting forecast of gas prices in effect represents a "quasi" upper limit for future prices given that the resource owner is constrained from collecting the optimum rent premium by the inherent uncertainty in the industry and the need for gas to compete with other fuels. In this sense, it is the resource owners' scarcity rent that is being compressed in today's environment of gas-on-gas competition and low oil prices. Natural gas is being priced more as a commodity than as an exhaustible resource in that competitive conditions have essentially bid away the scarcity rent component of prices. The resulting price does not compensate producers for the higher replacement costs they will have to bear in future years. It is essentially a price that just covers operating costs, royalty payments and any incremental investment required to produce existing reserves.

This perspective evokes a number of questions that are critical in assessing future gas prices:

- Is this type of behaviour solely the result of gas-on-gas competition caused by excess productive capacity? Is it the product of an increasingly competitive market structure in general combined with expectations of flat oil prices and thus sustainable when demand and supply are roughly balanced? Or, is it some combination of the two?

- Given expectations that oil prices will generally remain flat for the next 5 to 10 years and rise at a relatively slow rate thereafter, will the underlying cost of future gas supplies allow gas to be priced on an equivalent basis?

- If gas is priced according to fuel oil, will the resulting cash flow position of producers be sufficient to generate the requisite investment capital to produce higher cost gas supplies down the road? and, perhaps most importantly,

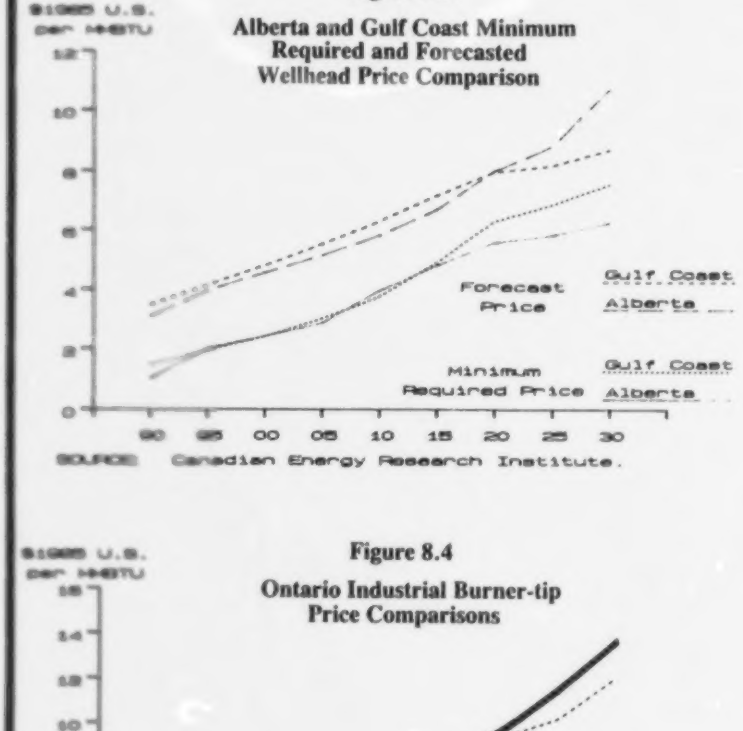
- Is this type of pricing structure rational? For example, by producing low cost gas supplies and selling them cheaply in the near term to meet fuel oil competition, it is conceivable that at some point in the future the exhaustion of these low cost supplies will result in large price increases and restrict the competitiveness of gas with other alternative fuels at that time (such as electricity). Thus, higher gas prices will have been foregone in the near to medium term and load loss and/or an extremely constrained cash flow position might be encountered in the long term.

Some insight into these questions is provided by comparing the wellhead prices calculated by the model with an approximation of the minimum required price to meet forecasted production levels for two regions--Alberta and the U.S. Offshore Gulf Coast. The minimum required price is estimated as that price required to yield to producers a 10 percent real rate of return on capital investment, and to cover operating costs. It is the bottom line for gas prices in the sense that it does not include taxes or royalties.

This comparison is provided in Figure 8.3. The model forecast indicates that conditions in U.S. markets could potentially drive the Alberta wellhead price up to $3.10 per MMBtu ($1985 U.S.) by the early 1990s and that this price could increase at an average annual rate of 3 percent thereafter. Wellhead prices are forecast to be slightly higher

Figure 8.3

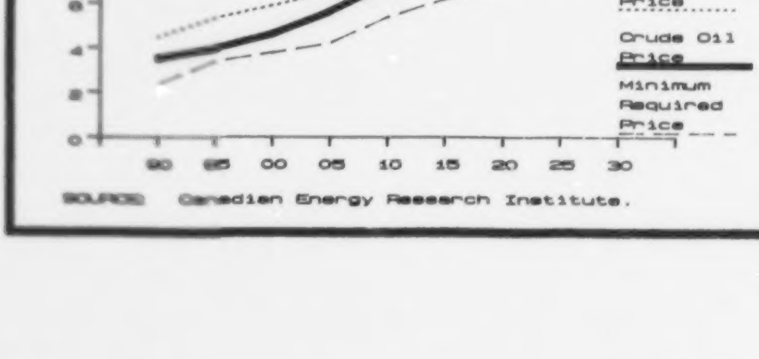
Alberta and Gulf Coast Minimum Required and Forecasted Wellhead Price Comparison



SOURCE: Canadian Energy Research Institute.

Figure 8.4

Ontario Industrial Burner-tip Price Comparisons



SOURCE: Canadian Energy Research Institute.

in the Gulf Coast region largely reflecting the differential in transportation costs between the two regions. The difference between these prices and the minimum required wellhead prices represents the scarcity rent. Low gas prices today imply that a large portion of this economic rent is flowing to consumers rather than the resource owners. This is a situation over which the Alberta Government has expressed considerable concern. The recent change in the natural gas royalty regime to establish a minimum price for royalty calculations reflects this concern.

Some other important observations that can be drawn from Figure 8.3 are, first, that the minimum required prices in Alberta and the Gulf Coast are very similar, with Alberta gas being slightly less expensive in the near term. This cost advantage is enhanced if, as we indicated in the discussion of Canada-U.S. gas trade, Alberta gas is produced at or near capacity as is the case in the U.S. Second, the minimum required price path is consistent with today's prices and suggests that there is scope for gas prices to remain competitive with fuel oil over the forecast horizon. This is illustrated in Figure 8.4 where gas prices at the Ontario industrial sector burner-tip (netted forward from the minimum required and forecast wellhead prices in Alberta) are compared with the oil price forecast underlying the demand projections. Finally, observe that the minimum required price increases significantly over time while concomitantly, the scarcity rent component is compressed. Thus, although the prices in the model may in the short term be unrealistically high, the longer-term prices are indicative of the cost structure underlying the gas resource base.

It must be remembered that the gas model produces a long-term price forecast. That is, it is the price track which over time will generate sufficient supplies to satisfy demand in every time period of the model's 45-year forecast horizon. As discussed above, the factors impacting on prices in the analysis are mainly supply driven because gas demand is exogenously specified. However, lower forecasts of future demand will result in lower near term prices as the benefits of delaying production are reduced.

While this forecast may be considered an upper bound, it does indicate that future gas prices may exceed the cost of residual fuel oil in certain industrial markets. We have also estimated a bottom line on gas prices which suggests that the cost structure of the underlying gas resource base can provide producers with enough downward flexibility to meet fuel oil competition. It is of critical concern whether or not these prices would justify sufficient drilling activity to replenish reserves on a consistent basis. Nevertheless, world oil prices will be a major determinant of future gas prices. A sufficiently flexible and competitive marketplace is needed to allow gas prices to be determined efficiently. The resulting market price will then reflect buyers' and sellers' perceptions and knowledge of the current and expected supply-demand situation and the current and expected prices of alternative fuels.

8.1.3 Future Production Sourcing

Figure 8.5 summarizes our forecast for the Canadian gas production sector. Alberta can be expected to remain the major Canadian producer of natural gas. Although the share of production from conventional reserves declines from about 86 percent of total Canadian production in 1990 to about 75 percent in 2005, actual production increases from 3.2 to 3.7 quads over the same period. Production levels in British Columbia and Saskatchewan are forecast to increase significantly from 0.44 and 0.067 quads in 1990 to 0.68 and 0.14 quads in 2005, respectively. This increased production is necessary to meet increasing domestic requirements and to exploit opportunities in U.S. markets.

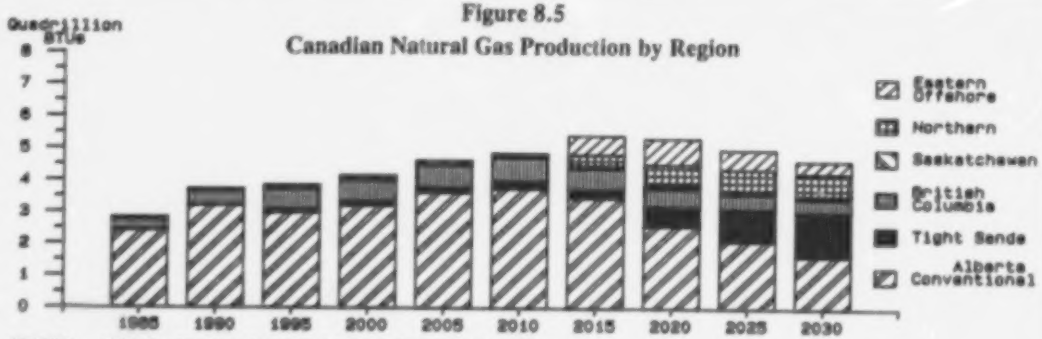
Given our assumptions regarding the cost and size of tight gas reserves in Alberta's deep basins, we forecast that production from these reserves will play an increasingly important role in meeting future demand requirements. Production of tight gas is forecast to become feasible by the mid-1990s. Initial production rates are forecast to be quite low, at about 0.10 quads in 1995, and increase over time to 0.16 quads in 2005 and 1.37 quads in 2030.

Given the uncertainty about the economics of tight gas production and advances in production technology, we examined the sensitivity of the reference case results to a case in which we assumed that no tight gas would be produced. This has the effect of significantly reducing the available reserves in the Western Sedimentary Basin. The dynamic nature of the model captures this impact by increasing the price (or value) of natural gas in every time period. As a result, exports to the U.S. are on average 20 percent lower than in the reference case.

For the production levels appearing in Figure 8.5 to be realized, reserves will have to be added at a considerable rate to

Figure 8.5

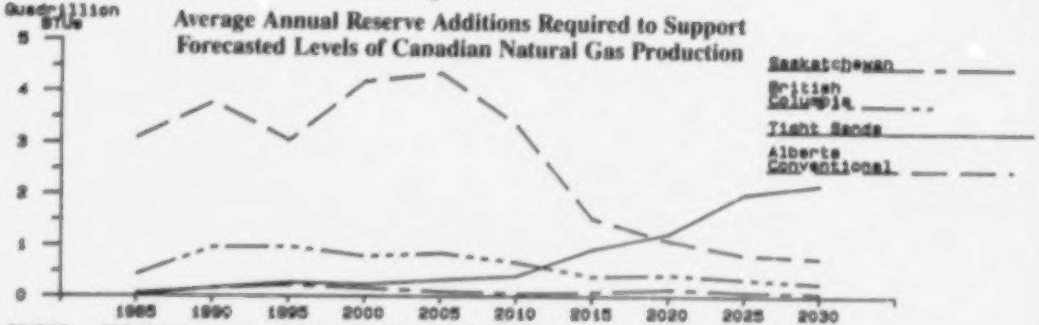
Canadian Natural Gas Production by Region



SOURCE: GRI North American National Gas Model, 1987.

Figure 8.6

Average Annual Reserve Additions Required to Support Forecasted Levels of Canadian Natural Gas Production



SOURCE: GRI North American Natural Gas Model, 1987.

offset depletion in established reserves. The required annual reserves additions are calculated by the model and provided in Figure 8.6 for the conventional supply regions. As illustrated, Canadian producers will have to add over 5 quads annually until 2005, whereupon the additions rate declines to just over 3 quads by the end of the forecast horizon. The long-term implication that these figures have for the Canadian gas industry is clear--an intensive, sustained drilling program will be required to meet forecast production levels. If an average finding rate of 1.0 Bcf per successful gas well (about the average observed between 1980 and 1985) is maintained throughout the forecast period, over 6000 successful gas wells would be required on an annual basis in the Western Sedimentary Basin through 2005 compared to the 1300 successful wells completed in 1986. While this represents a lower bound on the number of required wells because finding rates are likely to decline over time as prospects for new discoveries diminish, it does illustrate the magnitude of the drilling effort and capital investment that must be directed towards gas in the long term.

The efficient use and development of Canada's conventional and tight gas supplies delay the need for production from Canada's frontier regions until after 2010. The location of conventional and tight gas reserves relative to the existing pipeline network allows for significantly lower transportation costs and more competitive delivered prices relative to frontier supplies.[10] Depleting conventional supplies result in an increasing dependence on frontier supplies after 2010. Production from Northern Canada is forecast to exceed 0.3 quads by 2015 and reach 0.6 quads in 2020, the capacity of an expanded Polar Gas pipeline.

Production from Canada's Eastern Offshore region is expected to serve primarily the Mid Atlantic/New England region because of the prohibitive costs of building pipeline and distribution facilities to serve the Maritime provinces, Quebec, and Ontario.[11] Alberta gas is effectively displaced from the Northeastern states by Eastern Offshore gas after 2010. Production from offshore gas reserves is forecast to reach just under 0.6 quads in 2015, peak at about 0.8 quads in 2020 and decline thereafter.

Numerous other factors could impact on the timing and demand of Canada's frontier production. More intensive production of conventional reserves, unforeseen failures in tight gas production technology, and lower than expected conventional gas potential could all accelerate the need for frontier supplies. Our research, however, suggests that these factors do not significantly affect the timing of frontier production. For example, the assumption of no tight gas production, as discussed above, decreases export levels and thus does not appreciably affect the timing of frontier production. The observed impact is that initial year requirements increase considerably--they are 70 percent higher for Northern gas and 30 percent higher for Eastern Offshore, respectively, than in the reference case. Moreover, the demand for frontier gas is greater in every subsequent period.

It should be noted that as a number of major Northern fields have already been discovered, finding costs are essentially sunk and a great deal of the uncertainty regarding the region's gas potential has already been resolved. Lower development costs than assumed in this study could considerably accelerate the production prospects for this region.

Customers in the market for long-term, secure gas supplies could find the established reserves in Northern Canada very attractive. If a sufficient volume of gas could be sold under long-term contract with stringent cost recovery provisions, it is possible that a northern pipeline could be financed and put in operation shortly after 2000. Moreover, if the Alaska Natural Gas Transportation System (ANGTS) project is completed in the early 2000s, the economics of proposals such as the Dempster Lateral, which could utilize a part of the Alaskan system, might become more attractive than a stand-alone project like the Polar Gas proposal.

Production from offshore reserves will be determined by the economics of future discoveries relative to markets in the Northeastern U.S. Considerable economies of scale might be possible if a number of fields could utilize a common pipeline link to U.S. markets. Again, long-term contracts with stringent cost recovery provisions would be necessary to obtain the requisite financing for development of these projects.

Given the current uncertainty in gas markets and continued competition between gas suppliers, it is unlikely that buyers and sellers will forget today's lessons and re-enter into long-term, highly inflexible contracts. Extreme' imaginative financing and contract structures will eventually be required to bring Canadian frontier supplies to market.

Gas production in the U.S. is forecast to undergo some fairly pronounced regional and technological shifts over the 45-year time horizon. Table 8.1 summarizes the forecast of U.S. gas production by technology and by region. Gas production from Lower-48 conventional onshore reserves is expected to decline from about 9.5 quads in 1990 to 7.3 quads in 2010. This decline is offset somewhat by increased production from "deep" Lower-48 reserves, which is projected to increase from 1.5 to 3.1 quads over the same period. Production from Lower-48 offshore reserves is forecast to decline only slightly between 1990 and 2005, from 4.5 to 4.4 quads, although production declines quite rapidly thereafter. North Alaskan gas via ANGTS is required in significant quantities after 2005, exceeding 1 quad annually. In order to offset declining domestic production and Canadian imports, the U.S. will increasingly rely on coal gasification technology to meet domestic gas requirements after 2015. Other nonconventional sources such as gas from Devonian Shales, coal bed methane, and improved secondary gas recovery techniques which were not incorporated in the modelling framework could considerably reduce this dependency on coal gasification.

On a regional basis, the Anadarko, Gulf Coast, and West Texas supply regions show the most pronounced downward trend in gas production. Production from these regions is forecast to decline from about 2.9, 1.4, and 8.2 quads in 1990 to 2.3, 1.2, and 7.4 quads in 2005, respectively. Increased production from the Pacific, Rocky Mountain, and Appalachian supply regions somewhat offsets this trend. Combined production from these regions is forecast to increase from 3.3 to 4.8 quads over the same period.

8.2 Recommendations

This study provides a review of the evolution towards deregulated natural gas markets in Canada and the U.S., the essential precepts of the new market environment, and the impact of deregulation initiatives on the marketplace and on Canada-U.S. gas trade. It also discusses the long-term foundations of the North American gas industry by examining the determinants and potential for future gas supplies and demand. Finally, by integrating the two markets with the continental pipeline network in the North American Regional Natural Gas Model, the study has provided a comprehensive, long-term regional forecast of Canada-U.S. gas trade, gas prices and production sourcing. On the basis of the research work underlying this study and the results of our modelling efforts, the Canadian Energy Research Institute feels that the following recommendations are warranted:

TABLE 8.1
U.S. PRODUCTION OF NATURAL GAS
(quadrillion Btus)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
By Technology										
Lower 48 Onshore	9.86	9.45	9.38	9.33	8.49	7.29	6.31	5.24	3.81	2.39
Lower 48 Offshore	4.71	4.49	4.62	4.80	4.47	4.00	3.59	2.81	1.99	1.16
Lower 48 Deep	1.56	1.54	1.76	2.31	2.86	3.08	3.49	3.48	2.47	1.82
Alaskan	0.23	0.23	0.23	0.23	0.23	1.47	1.57	1.60	1.57	1.58
Lurgi Coal Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.47	2.67	6.64	10.61
Total	16.36	15.71	15.99	16.68	16.05	15.83	14.95	15.78	16.67	17.58
By Region										
Lower 48										
Pacific Coast	0.36	0.52	0.65	0.67	0.66	0.64	0.60	0.54	0.42	0.30
Rocky Mountains	1.50	1.85	2.29	2.60	2.67	2.63	2.79	3.16	3.27	3.37
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	2.13	3.90
Anadarko	2.83	2.46	2.29	2.30	2.27	1.95	1.87	1.59	1.15	0.71
West Texas	1.48	1.36	1.31	1.37	1.27	1.16	1.31	2.20	3.01	3.90
Gulf Coast	9.41	8.20	7.74	7.78	7.40	6.71	6.21	5.19	3.67	2.14
Midwest	0.12	0.12	0.11	0.11	0.10	0.08	0.09	0.15	0.29	0.43
Appalachian	0.43	0.96	1.35	1.63	1.45	1.23	0.99	1.08	1.17	1.25
Total Lower 48	16.13	15.48	15.76	16.45	15.82	14.36	13.39	14.19	15.10	16.00
South Alaska	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.22	0.18	0.15
North Alaska	0.00	0.00	0.00	0.00	0.00	1.23	1.23	1.37	1.40	1.43
Total U.S.	16.36	15.71	15.99	16.68	16.05	15.83	15.83	15.78	16.67	17.58

SOURCE: North American Regional Natural Gas Model.

Recommendation 1. The current policy direction of the federal and provincial governments regarding deregulation of Canada's natural gas industry should be continued. Attempts to limit core market participation in the direct sales market or to control downward movements in natural gas prices are inconsistent with the essential precepts of deregulation.

Recommendation 2. The federal and provincial governments and the natural gas industry should continue their efforts to ensure open access for Canadian natural gas to United States markets.

Recommendation 3. Canadian governments and industry should continue to place pressure on the U.S. Federal Energy Regulatory Commission to accelerate the elimination of those elements of the current U.S. regulatory framework which discriminate against U.S. imports of Canadian natural gas. Elimination of the large toll zones established by the FERC (which require that Canadian exporters moving gas to markets located a short distance from the border pay nearly the same transportation rate as U.S. producers moving gas from as far away as Texas) in their enforcement of the distance-related transportation rates called for in Order No. 500 and acceptable resolution of the "as-billed" decision (Opinion 256) are two such elements.

Recommendation 4. Initiatives which seek to explicitly control the price of Canadian gas exports to the United States must be avoided. The long-term distortionary impact of such initiatives on domestic prices and future market development outweigh any revenue gains which may accrue from such actions in the short term.

Recommendation 5. Government initiatives designed to restrict export volumes on the basis of security of domestic natural gas supply are not warranted, nor can the resulting impact on prices and market development be justified.

Recommendation 6. An in-depth, comparative assessment of the potential volume, economics and timing of development of Canadian tight gas reserves relative to northern frontier reserves is justified. Such an assessment should precede any development of Canada's northern frontier gas supplies.

Recommendation 7. Given the forecast potential for growth in demand for Canadian gas in both the domestic markets of Central Canada and in the Northeast United States, expansion of the TransCanada Pipeline system as requested in the current National Energy Board hearing is justified and should be pursued.

Recommendation 8. Increased pipeline capacity linking Western Canada to the Northeast United States either directly or via displacement should be vigorously pursued and lobbied for in the upcoming hearings of the U.S. Federal Energy Regulatory Commission on the matter of expanded pipeline delivery into the U.S. Northeast Region. Given the competitiveness of this market, it is critical that any approved proposal (or proposals) utilize existing facilities to the fullest possible extent in order to minimize the risk involved in new pipeline construction and the cost of transportation.

8.3 Areas for Future Research

The modelling framework underlying the North American Regional Natural Gas Model is extremely flexible and has considerable scope for future enhancements and refinements. The experience of the Institute with this analytical framework suggests a number of key areas for model refinement and future research:

- A more rigorous incorporation of demand-side realities and future prices. As we have discussed, gas prices which are calculated endogenously in the model are somewhat inconsistent with expected alternative fuel prices. One method for dealing with this problem would be to incorporate the fuel-switchable market into the demand side.[12] This would capture the impact of fuel switching on near- and long-term gas prices and demand if gas prices exceeded alternative fuel prices.

  A second method, which is more rigorous and complex, would be to endogenize gas demand. Each of the demand regions would be characterized by a demand model which would yield estimates of gas demand as a function of forecast trends in the prices of natural gas and competing fuels. The resulting gas demand and prices that equilibrate the various markets would thus be more reflective of both the costs of production and alternative fuel prices.

- More detailed regional disaggregation on the demand side. Further disaggregation of demand in the U.S. would permit more accurate identification of potential markets for Canadian gas.[13] In Canada, creating separate regions for Quebec and the Maritimes would permit a more rigorous assessment of potential markets in Eastern Canada.

- Expansion of existing and potential pipeline coverage. Expanding the coverage of potential U.S. pipeline facilities would allow for an assessment of such possibilities as shipping Rocky Mountain gas to the Northeastern states or alternative proposals to supply California's EOR market. Another interesting possibility would be to examine the impact of an expanded Northern Border pipeline system, in terms of both volume and service area, on export trade flows. Canadian gas could conceivably displace U.S. gas from the East North Central region into the Northeast markets. This might reduce, or even eliminate, the need for expanded Canadian pipeline access to the Mid Atlantic/New England region.

In Canada, if estimates of the cost of servicing the Maritime region were obtained, the potential for gas penetration into various Eastern markets could be assessed in more detail. An examination of alternative proposals to deliver Northern gas, such as the Dempster Lateral, might be warranted given that the study results suggest that ANGTS could be in service before Canadian frontier gas is required.

- Consolidation and expansion of supply side coverage. Given the inherent uncertainty about future gas resources, some additional sensitivity analysis of alternative resource assumptions in the U.S. is needed. This could include changes in the conventional resource base and the impact of possible advances in tight gas production, improved recovery technologies, and production from other nonconventional sources (such as methane from coal seams) on the ultimate gas potential in the U.S.[14] In Canada, future production costs could be more rigorously estimated, especially in the frontier regions. Given Alberta's substantial coal reserves, the potential for coal gasification should also be incorporated within the model.

No single response to the multitude of issues and questions facing the North American natural gas industry can claim to be definitive. This study has reported on the analysis of a number of the key issues facing the industry over the long term. In the process, the Institute has aided in the development of a powerful analytical tool which is extremely well-suited to the assessment of policy and development questions regarding the North American natural gas market. It is the intention of the Institute to continue work in this area, both in terms of refinements to the analytical framework as discussed above, and in further analysis of policy and development questions of import to the Institute and its audience. The Institute would appreciate and welcome any suggestions which appear appropriate for further research in this area.

Footnotes

[1] Table 5.3 provides a summary of seven such studies.

[2] Some of these fears were expressed by participants in the hearings held for the National Energy Board, Reasons for Decision in the Matter of A Review of Natural Gas Surplus Determination Procedures (Ottawa: Ministry of Supply and Services, July 1987).

[3] This view is presented in the Natural Gas Market Report, vol. 3, no. 19, October 30, 1987, p. 8.

[4] Such concerns appear regularly in U.S. trade publications. An example can be found in Natural Gas Week, vol. 3, no. 46, November 16, 1987, pp. 1 and 3.

[5] Gas production from Texas, Oklahoma, and Louisiana comprised about 77 percent of total production in 1986, according to statistics published by the U.S. Department of Energy, Energy Information Administration, Natural Gas Monthly May 1987 (Washington: DOE/EIA, July 1987) pp. 50-52.

[6] The inter-relationship between regional sources of supply and the transportation network in the Lower-48 states is discussed in a slightly different context in P. R. Holtberg and T. J. Woods, "The Implications of Changing Gas Transmission Patterns" in Proceedings from the Ninth Annual North American Meeting of the International Association of Energy Economists (Washington D.C.: November 1987), pp. 86-94.

[7] These estimates are provided by the National Energy Board.

[8] For example, to ship gas from Emerson to Suffolk, Massachusetts would cost $2.58 (U.S.) per Mcf. This route requires transportation on Midwestern, ANR, Texas Eastern, and Algonquin Gas. (Estimate and route provided by the Pathfinder system of the Enernet Corporation.)

[9] The scarcity rent compensates the resource owner for the higher finding, development, and operating costs that must be incurred in the future. Essentially, to maximize the net present value (NPV) of profits, a producer should set production so that the price just equals the marginal cost of production plus the NPV of holding that marginal unit in the ground for an additional year. If that marginal unit is produced today rather than waiting, the producer must incur higher finding, development and operating costs in all future production years. A detailed discussion and derivation of this version of Hotelling's rule can be found in S. M. Haas, et al., The GRI North American Regional Natural Gas Supply-Demand Model, (1987), pp. 4-1 and 4-9.

[10] The cost of transporting gas from the Taglu Field to Edson, Alberta on the Polar Gas pipeline is estimated to be $2.54 (1984 Cdn.) per Mcf in the first year of operation. Thus the total cost of transporting Northern gas to Eastern Canada would be about $4.00 per Mcf in the first year and the delivered price equal to the transportation cost plus the wellhead price. Note that if a 100 percent load factor was maintained on the northern pipeline, the transportation cost to Edson could decrease to $1.93 (1987 Cdn.) per Mcf within five years.

[11] In the Venture gas application to the NEB for an export license (June 1985), the applicants examined potential gas markets in the Maritimes. The study showed that the cost of the required distribution facilities severely limited the size of potential demand that could be served without subsidization.

[12] Decision Focus Inc., the developers of the gas model, are in the process of adding this feature to the model.

[13] For example, disaggregating the Pacific region into California and the Pacific Northwest, would allow for a more accurate representation of the existing pipeline facilities to these regions and accessible sources of supply. Thus, the potential for exports from British Columbia could be more explicitly identified.

[14] The Gas Research Institute uses the regional gas model to examine these types of issues in order to assess the potential impacts that its research efforts into improved production and recovery techniques might have on the marketplace. It has a number of scenarios of U.S. gas supplies that could readily be applied to examine the impact on Canada-U.S. gas trade.

APPENDICES

APPENDIX A

CONVERSION FACTORS

Appendix A

CONVERSION FACTORS

1 cu. ft. of natural gas = 0.028 327 84 m^3

1 m^3 of natural gas = 35.301 cu. ft.

1 Btu 60/61 = 1 054.615 J

1 J = 0.000 948 2 Btu 60/61

1 dt (dekatherm) = 1.0×10^6 Btu

1 hp = 745.699 9 W

1 W = 0.001 341 hp

1 MMcf = 28 327.84 m^3 or 28.327 84 $\times 10^3 m^3$

1 Bcf = 28 327 840 m^3 or 28.327 84 $\times 10^6 m^3$

1 Tcf = 28 327 840 000 m^3 or 28.327 84 $\times 10^9 m^3$

$1 \times 10^6 m^3$ = 35.301 MMcf

$1 \times 10^9 m^3$ = 35.301 Bcf

$1 \times 10^{12} m^3$ = 35.301 Tcf

1 standard U.S. barrel (oil) = 0.158 987 3 m^3

1 m^3 = 6.289 81 bbl (oil)

Approximations

1 m^3 of 31° API crude oil = 38.47 GJ (based on (5.8 MMBtu/bbl)

1 MMcf = 1.13 TJ (1 075 Btu gas)

1 TJ = 0.88 MMcf (1 075 Btu gas)

1 TJ = 0.95 MMcf (1 000 Btu gas)

SI Metric Prefixes

Prefix	Symbol	Meaning
mega	M	10^6
giga	G	10^9
tera	T	10^{12}
peta	P	10^{15}
exa	E	10^{18}

Imperial Prefixes

Prefix	Symbol	Meaning
thousand	M	10^3
million	MM	10^6
billion	B	10^9
trillion	T	10^{12}
quadrillion	quad	10^{15}

NOTE: All figures in this table are based on reference standard conditions of 15°C and 101.325 kPa (absolute) for SI units and 60°F and 14.73 psia for Imperial units unless otherwise noted.

Gross Energy Content Factors

Natural Gas		
B.C.	- domestic	39.10 MJ/m^3
	- Huntingdon	39.10 MJ/m^3
	- Kingsgate	37.65 MJ/m^3
	- Grassy Point	38.20 MJ/m^3
Alberta	- domestic	38.80 MJ/m^3
	- Cardston	37.65 MJ/m^3
	- Aden	36.06 MJ/m^3
East of Alberta		37.65 MJ/m^3
Ethane (liquid)		18.36 GJ/m^3
Propane (liquid)		25.53 GJ/m^3
Butanes (liquid)		28.62 GJ/m^3
Crude Oil		
Light and Medium		38.51 GJ/m^3
Heavy		40.90 GJ/m^3
Pentanes Plus		35.17 GJ/m^3
Coal		
Bituminous		29.30 GJ/tonne
Subbituminous		19.76 GJ/tonne
Lignite		15.35 GJ/tonne
Average domestic use		24.00 GJ/tonne
Petroleum Products		
Aviation Gasoline		33.52 GJ/m^3
Motor Gasoline		34.66 GJ/m^3
Petrochemical Feedstocks		35.17 GJ/m^3
Naphtha Specialties		35.17 GJ/m^3
Aviation Turbo		35.93 GJ/m^3
Kerosene		38.68 GJ/m^3
Diesel		38.68 GJ/m^3
Light Fuel Oil		38.68 GJ/m^3

Lubes and Greases	39.16 GJ/m^3
Heavy Fuel Oil	41.73 GJ/m^3
Still Gas	44.46 GJ/m^3
Asphalt	44.46 GJ/m^3
Petroleum Coke	42.38 GJ/m^3
Other Products	39.82 GJ/m^3
Electricity	
Secondary	3.6 MJ/kW.h
Primary Hydro	3.6 MJ/kW.h
Nuclear	12.1 MJ/kW.h

APPENDIX B

GAS INDUSTRY GLOSSARY

Appendix B

GLOSSARY OF TERMS

ABANDONMENT: Authority granted by the FERC to abandon facilities or service rendered by a natural gas company in interstate commerce. Producers and pipelines recently have sought limited-term or permanent abandonment of gas from dedication to the interstate market. Abandonment of this gas allows producers to find new buyers at newly negotiated rates. Gas not subject to FERC jurisdiction does not require abandonment (this includes large volumes of gas now moving in interstate commerce).

AFFILIATED MARKETER: A marketing company that is owned either by an interstate pipeline, or a corporation that also owns an interstate pipeline subsidiary.

AFFILIATED ENTITIES TEST: A regulatory test administered by FERC that determines whether the amount a pipeline pays to its affiliated producer exceeds the amount it paid in comparable deals with non-affiliated companies.

AS-BILLED RATES: A policy allowing pipelines to flow through gas costs to their customers in the same manner as they are billed to the pipeline. (For example, demand charges paid by the pipeline would be included in demand charges billed to its customer; commodity charges would be flowed through in the same way.) Currently Canadian suppliers want to flow their charges through to American customers on an "as-billed" basis. FERC has declared that those charges should be billed to American customers using U.S. ratemaking formulae. American producers think the "as-billed" treatment gives Canadian gas an unfair competitive advantage by loading up the demand charge and cutting commodity rates, while Canadians argue that the rate is based on contractual agreements worked out years ago--agreements based on the cost of building facilities in Canada to serve the American market.

BALANCING: Making deliveries of gas into or withdrawals from a pipeline equal to the contracted amount or space. Balancing may be accomplished daily, monthly, or seasonally, with penalties generally assessed for excessive imbalance.

BLANKET CERTIFICATE: A FERC authorization covering multiple transactions under a single certificate.

BUY/SELL: In this arrangement, the end-user purchases its own supply of gas and arranges for transportation generally to the distributor's delivery point. The distributor purchases the gas and comingles it with the balance of its supplies, and then sells to the end-user as a sales customer at a rate lower than if the end-user had not made the direct purchase.

BY-PASS: Method by which a customer gains access to direct deliveries of gas from a supplier other than its traditional supplier. Distributors may "by-pass" their pipeline supplier by building interconnects to other pipelines; industrial customers may "by-pass" their local distributor by tapping directly into an interstate pipeline.

CASINGHEAD GAS: Gas produced with oil in oil wells; taken from the well through the casinghead at the top of the well. Casinghead gas has high priority for delivery under state prorationing laws, since shutting in gas would also mean shutting off oil production.

CD WAIVER: An authorization by the FERC that temporarily suspends the obligation of a pipeline under Order 436 to allow customers to reduce or eliminate their contract demand over a 5-year period.

CEILING PRICE: The maximum lawful price which may be charged. Applies only to regulated gas.

CITY-GATE: Physical location where gas is delivered by a pipeline to a local distribution company.

COAL GASIFICATION: The production of synthetic natural gas from coal.

COGENERATION: The sequential production of electricity and useful thermal energy from the same energy source. Natural gas is a favored fuel for combined-cycle cogeneration units, in which waste heat is converted to electricity.

COMMODITY CHARGE: That portion of a natural gas rate based upon the volume actually purchased.

COMPETITIVE MARKETING PROGRAMS: The 31 October 1985 Agreement among the Governments of Canada, Alberta, British Columbia and Saskatchewan on Natural Gas Markets and Prices provided for the implementation of competitive marketing programs. These were programs under which price discounts were accorded to industrial gas users in order that gas be competitive with the costs of competing fuels.

CONTRACT DEMAND: The daily, monthly, or annual quantity of gas which the supplier agrees to furnish and for which the buyer agrees to pay a demand charge.

CORE MARKET: A term whose definition is not generally agreed to. Some parties use it to denote those natural gas users who are unable to switch readily to alternative fuels or who cannot or do not wish to contract directly for their supply needs, instead purchasing gas from distributors. Some parties consider the core market to include residential, commercial, and small industrial customers, although there is no general agreement on what should constitute "small." Some parties consider the core market to include all customers of local distribution companies.

CURTAILMENT: Reduction of gas deliveries because of a shortage of supply or because demand for service exceeds a pipeline's capacity. Usually there is a hierarchy of customers, in which some may be required to partially or totally cut back takes of gas before others.

CUSTOMER CLASSES: The common classes of customers who receive service from a utility are: residential, commercial, industrial, and sale-for-resale.

DECLINE PERIOD: The period between the end of the reservoir's flat-life period and abandonment, during which production is decreasing.

DEEP GAS: Generally defined as gas found at depths below 15,000 feet.

DEMAND CHARGE: The portion of a gas charge that reflects a customer's contract requirements. Usually a set monthly fee, based on estimated volume contract requirements.

DEREGULATION: (or decontrol) are commonly used terms to describe efforts by the Canadian and U.S. governments to limit regulation of the natural gas industry. Generally, the price in both countries is now market determined while transportion costs remain regulated.

DIRECT SALES: are a transaction agreement whereby an end-user purchases gas directly from a producer or marketer thus bypassing the system sales of the LDC and pipeline while still using their facilities to transport the gas.

DISPLACEMENT: The method by which equivalent volumes of gas are delivered from one point on a pipeline's system to another point without a continuous flow of molecules from the first point to the second. Sometimes also called a "backhaul."

DOUBLE DEMAND CHARGE: The duplication of demand charges which occurs when a customer, who previously purchased gas through a distributor, arranges an alternate supply through a direct purchase. In these circumstances, the direct purchaser is required to pay the demand toll twice: once to the transmission pipeline company for transportation service and once to its distributor to indemnify the distributor for the unabsorbed demand charges which occurred as a result of the displacement. The payment of double demand charges was eliminated effective 1 November 1986. (See NEB, "Reasons for Decision in the Matter of TransCanada Pipelines Limited Availability of Services," May 1986).

ECONOMIC REGULATORY ADMINISTRATION (ERA): Division of the Department of Energy that regulates imports and exports of natural gas. Forrestal Building, Room 5B-148, Washington, D.C. 20585. (202) 586-2929

ENHANCED OIL RECOVERY (EOR) FIELDS: Reservoirs in which secondary recovery techniques are used to extract oil. Most notably, EOR fields in Kern County, California, are expected to use large amounts of natural gas in the future to produce steam for secondary recovery, as well as electricity which will be sold to local utilities.

ENERGY INFORMATION ADMINISTRATION (EIA): Statistical information collection and analysis branch of the Department of Energy. Forrestal Building, Room 1F-048, Washington, D.C. 20585. (202) 586-8800.

ESCALATOR CLAUSE: A clause in a purchase or sales contract which permits adjustment of price or profit, under specific conditions.

ESTABLISHED RESERVES: Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.

ESTIMATED PROVED RECOVERABLE RESERVES: An estimated quantity of natural gas which analysis of geologic and engineering data demonstrates with reasonable certainty to be recoverable in the future from known oil and gas reserves, under existing economic and operating conditions. Reservoirs are considered proved that have demonstrated the ability to produce by either actual production or conclusive formation tests.

EXCHANGE GAS: Gas received from (or delivered to) another party in exchange for gas delivery to (or received from) such other party, often in a displacement arrangement.

FEDERAL ENERGY REGULATORY COMMISSION (FERC): A federal agency created in 1977 to regulate, among other things, interstate wholesale sales and transportation of gas at "just and reasonable" rates. Formerly the Federal Power Commission.

FEEDSTOCK GAS: Gas used as a raw material for its chemical properties in creating an end product (such as plastics and fertilizer).

FERC OUT: Clause in a producer/pipeline contract that allows a pipeline to adjust the price to reflect regulatory actions by the Federal Energy Regulatory Commission.

FIRM SERVICE: The highest quality sales or transmission service offered to customers under a filed rate schedule which anticipates no planned interruption. Usually associated with distribution companies that serve residential customers and other "high priority end-users," but can also apply to upstream pipelines and other customers.

FLAT LIFE: That period of the producing life of natural gas during which production is maintained at a constant rate before decline commences.

FORCE MAJEURE: An "act of God" or unexpected and disruptive event beyond the control of buyer or seller which interferes with a party's ability to perform under a contract. A force majeure event will typically relieve a party from a contractual obligation.

GAS BUBBLE (OR "SAUSAGE"): An oversupply of deliverability prevalent in the U.S. gas market since 1982-83. Originally predicted to last 18 months, it is now variably predicted to end in the winter of 1987-88 or go on indefinitely.

GATHERING SYSTEM: Includes pipelines and other equipment to move gas from the wellhead to a major pipeline system.

GRANDFATHER CLAUSE: The continuation of a former rule, clause or policy where a change to a new rule would be unfair to those covered by the former.

HEAVY FUEL OIL: The term heavy fuel oil generally refers to bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil).

HINSHAW AMENDMENT: A section of the Natural Gas Act which exempts from FERC regulation the transportation and sale for resale of interstate natural gas provided that it is received within the boundaries of a state, it is consumed within the state, and the facilities and rates are regulated by the state.

INCREMENTAL COST: Costs incurred from producing or delivering additional units of gas. To determine the incremental unit cost, the added cost is divided by the added capacity or output.

INCREMENTAL PRICING (NGPA): Pricing mechanism which passed through certain costs of acquiring new gas through a surcharge to some industrial customers using gas as a boiler fuel to generate steam or electricity. The purpose was to shield residential and other high priority users from the full impact of higher prices authorized by the NGPA.

INDEFINITE PRICE CLAUSES: Contract clauses that allow the price of natural gas to change, typically based on changes in prices of other commodities or gas supplies. Usually of two types--favored nation clauses and oil related clauses. Favored nation clauses match contract prices to the highest existing prices in a given area; oil related clauses link gas prices to a certain percentage of oil prices. An "Indefinite Price Escalator" may allow only for price increases, not decreases.

INDEPENDENT PRODUCER: Usually refers to a non-integrated producing company. Generally, the independent producer has operations only in the field of production.

INITIAL ESTABLISHED RESERVES: Established reserves prior to the deduction of any production.

INTEGRATED COMPANY: A company that gains revenue from gas production, distribution and transmission.

INTERIM 311 TRANSPORTATION: Self-implementing transportation under Order 436, subject to a temporary waiver of the contract demand reduction/coversion provisions of the rules.

INTERRUPTIBLE SERVICE: Gas service which is subject to interruption at the option of the pipeline. Also referred to as "best efforts." Tariffs for interruptible service (both sales and transportation) are lower than for firm service.

INTERSTATE GAS: Gas transported in interstate pipelines to be sold and consumed in states other than that in which the gas was produced.

INTRASTATE GAS: Gas sold and consumed in the state where it was produced and not transported in interstate pipelines.

LDC: Local distribution company.

LIQUIFIED NATURAL GAS (LNG): Natural gas liquified by reducing its temperature to minus 260 degrees Fahrenheit (remaining a liquid at -116 degrees). During the 1970s LNG facilities were built in the U.S. to accommodate imports of gas from Algeria and other overseas suppliers. The gas was shipped to the U.S., transformed back into a gaseous state and transported to end-users through pipeline systems.

MARKET OUT: A price clause in a producer/pipeline contract that allows a pipeline to adjust the price to be market responsive.

MARKETER: A company, other than a pipeline or LDC, that buys and resells gas or brokers gas for a profit. Marketers also perform a variety of related services associated with moving their product to buyers, including arranging transportation, monitoring deliveries and balancing. An independent marketer--as opposed to an affiliated marketer--is not affiliated with a pipeline or LDC.

MINIMUM BILL: Amount that must be paid by a pipeline's customer, over and above a demand charge, whether the customer takes the gas or not. FERC's Order 380 series generally eliminated variable cost minimum bills and minimum takes imposed by interstate pipelines.

NATURAL GAS: Gaseous hydrocarbons--principally methane--found in porous geological formations.

NATURAL GAS ACT OF 1938 (NGA): Federal law giving FERC jurisdiction over: (1) interstate transportation of gas; (2) the sale in interstate commerce for resale of gas; and (3) companies that are organized in either of the above.

NATURAL GAS LIQUIDS (NGL): The hydrocarbons ethane, propane, butane, and pentanes plus, or a combination thereof.

NATURAL GAS POLICY ACT OF 1978 (NGPA): Enacted in an era of concern over energy shortages and increasing reliance on oil imports, this federal law adopted a phased-in deregulation for "new" natural gas, or gas discovered after 1977 ("old" gas was to remain regulated) and incentive prices for certain types of natural gas to encourage increased exploration and production. Also established an incremental pricing surcharge to some industrial users.

NETBACK PRICING: A contractual arrangement in which the price of gas at the wellhead is based on what it sells for at the burner-tip. The market price is defined as the burner-tip price less transportation and distribution costs, and the profit margins of pipelines and distribution companies.

NEW GAS: Generally refers to deregulated gas. Several NGPA categories were officially price-deregulated on January 1, 1985: new natural gas; new onshore production wells at depths of 5,000 feet or less; some gas under existing intrastate contract. Most categories of high-cost gas have been price deregulated since 1979.

NON-ASSOCIATED GAS: Natural gas not in contact with crude oil in the reservoir.

NOTICE OF INQUIRY (NOI): Procedure used by the Federal Energy Regulatory Commission to gather information on a specified industry issue. Normally calls for comments from all interested parties and in some cases, reply comments and/or public hearings.

NOTICE OF PROPOSED RULE-MAKING (NOPR): A proposal by the FERC to change its rules. Sometimes preceded by a Notice of Inquiry. Normally calls for comments from all interested parties and in some cases, reply comments and/or public hearings. A NOPR may or may not result in a final rule.

OFF-PEAK: The period when a load being delivered is not at or near the maximum volume delivered by that system for a corresponding period of time, for instance, the summer months for a northern, heat-sensitive customer.

OLD GAS: Generally refers to gas in the U.S. that continues to be price-regulated.

OPERATING DEMAND VOLUME: Is the volume used by the NEB to determine an LDCs demand toll liabilities to TCPL. This concept eliminates duplication of demand charges by calculating a distributors CD volumes as those specified in its CD contract with TCPL less the volume of all direct sales occuring in its franchise area.

ORDER 380: A 1984 FERC Order that eliminated gas costs from an interstate pipeline's variable cost minimum bills and minimum takes.

ORDER 436: A FERC rule promulgated in October, 1985, establishing a voluntary, open-access system of transportation. The major components of the rule are: an expedited abandonment policy; blanket certification and self-implementing non-discriminatory 311 transportation; and optional, expedited certificates for new pipeline projects. Order 436 transportation includes an option for the pipeline's firm customers to reduce their contract demand for sales volumes over a five-year period. Transportation is also to be allocated on a "first-come", first-served" basis.

ORDER 451: FERC Order allowing the various price categories of old gas to rise through negotiation to the price of the highest old gas category ($2.63 per Mcf in April, 1987). Embodies a "good faith negotiation" procedure by which producers and pipelines can renegotiate certain gas prices for both cheap, "old" gas, and "new" gas that falls within the same contracts.

PEAK SHAVING: Supply of fuel gas for distribution systems from an auxiliary source (of limited supply, higher cost) during periods of maximum demand when the primary source is not adequate.

POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978 (FUA): Rising concern over oil imports led to the creation of the FUA, which prohibited the use of natural gas and oil in new powerplants and major fuel burning installations. The Department of Energy routinely issued exemptions to the FUA, and in May 1987, Congress repealed the Act.

PERMEABILITY: Permeability is a property of a porous medium and is a measure of the capacity of the medium to transmit fluids (common unit of measurement is the millidarcy).

PRICE CEILING: Statutory maximum lawful prices for various categories of regulated natural gas.

PRICING SYSTEMS: Natural gas prices are generally quoted at the wellhead, delivered in major pipeline system, at a city-gate, or at the burner-tip.

PROCESS GAS: Gas use for which alternate fuels are not technically feasible (applications requiring precise temperature controls and flame characteristics).

PRODUCTIVE CAPACITY: The estimated rate at which natural gas, crude oil or crude bitumen can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the availability of gathering, processing and transmission facilities, and potential losses due to mechanical breakdown.

PRORATIONING: The regulated balancing of oil or gas production among wells in a particular area. This issue is covered by state law and regulation in producing states.

PURCHASED GAS ADJUSTMENT (PGA): An adjustment to an effective pipeline sales rate to reflect the fluctuating cost of purchased gas. The PGA permits pipelines to track changes in gas purchase costs in order to pass them along to customers more quickly than with other, more stable costs.

RATE BASE: The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return.

RATE CASE: The regulatory procedure in which a pipeline, its customers, and the regulatory agency set new overall rates, usually including an evidentiary hearing, a settlement or decision by an administrative law judge, and a final decision by the full Commission.

RATE DESIGN: The method of classifying fixed and variable costs between demand and commodity components. Different formulas include United, Seaboard, Straight Fixed Variable (used in Canada), and Modified Fixed Variable (used in the U.S.).

RATE DISCOUNTING: FERC's Order 436 permits pipelines to discount their transportation rates to selected customers so long as the discount is absorbed by the pipeline's shareholders. Discounted rates are also known as "flex rates."

RATE OF TAKE: The average daily rate of production of natural gas related to the volume of initial established reserves assigned to the reservoir or reservoirs from which the production is obtained. For example, 1:7300 means one unit of production a day for each 7 300 units of initial established reserves.

REPROCESSING SHRINKAGE: The reduction in the quantity of natural gas arising from the removal of natural gas liquids (ethane, propane, butanes, and pentanes plus) at "straddle" or "reprocessing" plants located on main gas transmission systems.

RESERVES-TO-PRODUCTION RATIO (R/P RATIO): A ratio of the size of a gas field to the annual production capacity of that field which is used to estimate the productive life of the field.

ROYALTY: The amount paid to mineral owners. In gas and oil operations, usually based on a percentage of the total production.

SECTION 7(c) TRANSPORTATION: Section 7(c) of the Natural Gas Act is FERC's authority to issue certificates for transportation and sale-for-resale of gas in interstate commerce. It can do this individually, or generically (as in the various blanket certificate programs and Order 436). Today Section 7(c) transportation typically refers to orders approving specific transportation proposals for identified shippers and pipelines.

SECTION 311 TRANSPORTATION: Authority given to interstate pipelines (under Section 311 of the Natural Gas Policy Act) to move gas "on behalf of" distributors or intrastate pipelines. New 311 deals (generally those signed after 1985) are considered part of Order 436. They are self-implementing and do not require blanket certification. Pipelines who continue to offer new 311's must do so in a nondiscriminatory manner and are subject to contract demand reductions by their firm customers under Order 436 rules (unless FERC has issued a waiver of the rules). Intrastate pipelines may perform 311 transportation on behalf of interstate pipelines or distribution companies served by an interstate pipeline.

SHUT-IN WELL: A well that has been completed but is not producing. It may be shut-in for tests, repairs, or to await construction of gathering lines. In recent years, wells have been shut-in when buyers refused to take the gas, or when producers decided that the market prices offered for the gas were not sufficient to meet operating costs.

SOLUTION GAS: Natural gas in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.

SPECIAL MARKETING PROGRAMS (SMPs): A program launched by FERC (now ruled illegal by the courts) that allowed producer gas--previously committed to a pipeline or distribution company--to be released and sold at market prices to an end-user or distributor whose alternative gas or fuel sources enabled them to switch suppliers rather than pay the higher prices generally charged by the pipeline. FERC intended the SMPs to allow gas producers to make price concessions on gas that would otherwise be shut-in in order to market their gas and relieve pipelines of take-or-pay liabilities. The D.C. Circuit Court of Appeals found that the SMPs discriminated against "captive" customers.

SPOT MARKET: A market characterized by short-term, interruptible (or best efforts) contracts for specified volumes of gas.

STORAGE: Subsurface facilities used to store gas which has been transferred from its original location. Usually consists of natural geological reservoirs like depleted oil or gas fields or water-bearing sands sealed on the top by an impermeable cap rock.

TAKE-OR-PAY: The clause in a gas supply contract which provides that for a specific period a specific minimum quantity of gas must be paid for whether or not delivery is accepted by the purchaser. Some contracts contain a time period in which the buyer may take later delivery of the gas without penalty.

TAKE-AND-PAY: Clause that requires a minimum quantity to be physically taken and paid for, usually gas in association with oil, or wells that will be damaged by failure to produce.

TIGHT SANDS: Gas-bearing geologic strata that holds gas too tightly for conventional extraction processes to bring it to the surface at economic rates without special stimulation.

234-B TRANSPORTATION: A blanket certificate program of FERC (Order 234 series) which allowed transportation on behalf of low-priority end-users. Phased out and replaced by Order 436 after the D.C. Circuit Court of Appeals in 1985 required the imposition of a nondiscrimination condition on the program.

ULTIMATE POTENTIAL: An estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of the area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves and future additions through extensions and revisions to existing pools and the discovery of new pools.

WACOG: Weighted Average Cost of Gas. Formula used by pipelines to determine the cost of gas underlying their sales rates.

WELLHEAD: Specifically, the equipment at the top of a well for maintaining control of the well. More generally, it is used to specify a reference or delivery point on the production system.

APPENDIX C

A CHRONOLOGICAL HISTORY OF CANADIAN AND U.S. REGULATORY DEVELOPMENTS

Appendix C

A CHRONOLOGICAL HISTORY OF CANADIAN AND U.S. REGULATORY DEVELOPMENTS

C.1 U.S. Regulatory Developments

1938	The National Gas Act (NGA) is implemented as the first instance of federal regulation directed at prices charged LDC's by interstate pipelines.
1954	The "Phillips" Decision extends the application of the NGA to wellhead prices of gas sold to interstate pipelines. This in effect creates a divided market--interstate vs. intrastate. Gas produced and consumed in the same state was not regulated by the Federal Government.
1978	The National Gas Policy Act (NGPA) is passed by Congress. This act is intended to eliminate the division between the interstate and intrastate markets and to allow gas prices to rise to market clearing levels, providing greater incentives to increase domestic supply. Title I of the Act establishes 24 categories of gas and price ceilings for each of the categories. The ceilings were based on the physical characteristics of the well, the deposits into which they were drilled and the year in which the well was dedicated to interstate commerce. "Old" natural gas was limited to current prices plus an inflation adjustment. "New" gas was entitled to receive a higher price plus inflation and escalators designed to move the price toward market clearing levels. Certain gas categories qualified for special incentive prices at relatively high levels. A time schedule was set for the eventual decontrol of many new gas prices. Title II of the Act, the incremental pricing provision, was designed to minimize the burden of additional costs to the captive residential and commercial sectors associated with expanding gas service to Industrial Users. The incremental pricing provisions reserved the advantage of old gas for high priority users thus limiting

the impact on the residential/commercial sector to wellhead prices prescribed in Title I of the NGPA.

The Powerplant and Industrial Fuel Use Act, referred to as the Fuel Use Act (FUA) prohibits gas as a fuel for new electricity generating plants and large industrial applications. The Act also provides for existing plants to switch fuels by 1990; this portion of the Act was repealed in 1981.

The Public Utilities Regulatory Policies Act (PURPA) is passed with 3 objectives in mind; to encourage the conservation of energy, to encourage the efficient use of utility facilities and resources, and to ensure equitable rates for utility customers. The impact of PURPA on the natural gas industry is the creation of a new end-use market. Certain provisions within the Act stimulated the proliferation of cogeneration facilities. These provisions allowed operators to sell electricity to utilities at avoided costs (the cost the utility would incur to provide power to its customers if it were not receiving this power) while purchases could be made under prevailing tariffs. Natural gas used in certain cogeneration units is exempt from the incremental pricing provision of Title II of the NGPA.

1983 FERC introduces experimental Special Marketing Programs (SMPs) to help protect dual-fired markets not having access to cheap gas. The SMPs allowed a pipeline to release gas from system dedication and transport under NGA Section 7(c) at incremental tariffs. However, in order for pipelines to implement the program, it is necessary for producers to grant commensurate take-or-pay relief to pipelines.

FERC begins granting blanket certificates to move third-party gas under Section 311 of the NGPA at incremental tariffs. Order No. 319 allows interstate pipelines to obtain blanket certificates to transport gas for high priority end-users (e.g., schools, hospitals, feedstock). In effect, the procedure authorizes direct sales from producers to high priority end-users. Order 234-B effectively allows direct sales from producers and intrastate suppliers to industrial boiler fuel users. Gas can be sold and

	transported for up to 120 days without prior approval from FERC. An important result of this ruling is the creation of the spot market.
1984	FERC Order 380 is issued prohibiting pipelines from using "minimum-bill" provisions in sales contracts to recover variable costs such as purchased gas costs that are not actually incurred. This effectively prevents pipelines from passing on to their customers take-or-pay charges incurred in their supply contracts.
1985	Ceiling prices for most new gas volumes are removed as stipulated in the NGPA.
	SMPs and the blanket certificate program are ruled illegal by a Federal Court. The programs were said to discriminate against the pipeline's captive customers and were viewed as being monopolistic in nature (Maryland People's Council vs. FERC).
	FERC Order 451 is issued establishing an alternative ceiling price for "old gas" equal to the NGPA Section 190 price ($2.626 U.S./MMBtu in April 1987). The Order seeks to end market distortions created by the remaining cushion of old gas selling at below market value due to the low price ceiling originally set forth in the NGPA.
October 9, 1985	FERC Order 436 is issued in an effort to "open up" the U.S. natural gas pipeline network. The Order requires pipelines that transport for some to transport for all on an equal basis. Both firm and interruptible service must be offered and pipelines must charge cost-based, fully allocated transportation rates. A key provision of the order is that LDC's have the right to trade their firm contract demand rights for firm transportation rights over a period of five years or to reduce contract demand over the same period.
	Another component of Order 436 is the optional expedited certificate procedure designed to reduce barriers to new market entrants. However, pipelines applying for the certificate will have to assume all economic risk associated with the project, as opposed to being guaranteed a rate of return on their investment. Finally, in Order 436 the Commission has provided a new

abandonment policy under which a producer may obtain expedited abandonment.

1986 FERC Opinion 256 is issued forbidding Canadian pipeline demand charges to be passed on as billed in a U.S. pipeliner's charges. Essentially, the opinion was rendered because of differences in the manner in which pipeline tariffs are regulated in the two countries. Canadian tariffs require that the pipelines' fixed costs be recovered from the demand portion of the tariff. In the U.S. some of the fixed costs are loaded into the commodity portion of the tariff. As a result, U.S. pipelines carrying U.S. gas found their commodity costs higher than those pipelines carrying Canadian gas. FERC felt that this conferred the latter pipelines a competitive advantage and issued the opinion to "level the playing field."

1987 The Fuel Use Act (FUA) is repealed by Congress in May. Although liberal waivers had been routinely granted in the past, the repeal of the Act will formally free gas to be used as a primary fuel in electricity generation.

The D.C. Circuit Court vacates Order No. 436 in June. The Court upheld most aspects of the program--most notably FERC's authority to restructure the market and mandate nondiscriminatory transportation--but objected to several major aspects--primarily the CD reduction mechanism and failure of the FERC to adequately address the take-or-pay problem.

FERC creates "open-season" on competing proposals to serve the Northeast Markets in July. The intent of the action is to settle all outstanding proposals to service the U.S. Northeast market. The FERC did approve the Boundary Phase II plan which allows 15 U.S. LDCs to import gas through Niagara. All other competing projects, such as the Erie, Iroquois Pipeline, and MIDCUN proposals, will have to be refiled under the "open season."

The FERC issues an interim open access order in August, Order No. 500, the backbone of which is the FERC's response to the take-or-pay problem. The Commission chose a three-pronged approach to this problem: creating a new mechanism to direct-bill past take-or-pay charges; forcing producers to credit current transportation volumes against accruing take-or-pay liabilities; and providing pipelines with general guidelines to develop direct-billed surcharges for firm sales customers to alleviate future take-or-pay problems. In addition, the Commission eliminated provisions for contract demand reduction while keeping contract demand conversions intact.

Producers vigorously protest the crediting mechanism of Order No. 500 saying that the original deadline of November 1 for take-or-pay credits gave them insufficient time to prepare the necessary affidavits. In response to this criticism, the FERC issues Order No. 500-B which extends this deadline until January 1, 1988. (The order also extends the deadline for contract conversion waivers to the same date.) Criticisms continue regarding various aspects of the order. Order No. 500-C is issued in December in a further attempt to ameliorate these concerns. Target data for a final ruling is April 1, 1988.

C.2 Canadian Gas Regulatory Developments

November 1975

Until this point, both export and domestic prices were negotiated between buyers and sellers. The resulting prices were deemed to be below competitive levels by the governments of the producing provinces and in November 1975, the Alberta and Federal governments, under the terms of the National Gas Pricing Agreement (NGPA), set the interprovincial price of gas at $1.25/Mcf at the Toronto City Gate. This price was judged to be 85 percent of the Btu equivalence of crude oil. From this point till 1980, the interprovincial price was redetermined with each escalation in the domestic price of crude oil in an attempt to maintain the 85 percent Btu equivalence at the Toronto City Gate.

1976

Prior to 1976, Canadian export prices were set with regard to competing fuels in particular regions and the price therefore varied somewhat from market to market. U.S. requests a uniform border price for natural gas to avoid discrimination between states. Gas prices which were set at $1.60/Mcf (Cdn.) as of Nov. 1, 1975 are subsequently increased to $1.80/Mcf in September 1976 and $2.00 in January 1977.

1977	Canadian government adopts the substitution value approach to setting a uniform border price, linking it to the price of crude oil imports. Export prices are increased to $2.25/Mcf as of September 1.
1978	TCPL seeks producer support for the establishment of a gas prorationing plan, because gas available under existing purchase contracts has increased faster than TCPL's sales.
1979	Concurrent with rising world oil prices (world oil prices increase from $13.00 (U.S.) in January to $34.00 (U.S.) in October 1981) the Federal government approves an increase in the price of gas exports to $2.30/Mcf (U.S.). The practise of setting gas exports in terms of U.S. dollars had just recently begun due to a decline in the value of the Canadian dollar. Effective August 11, gas export prices are increased to $2.80/Mcf (U.S.). Effective November 4, gas export prices are increased to $3.45/Mcf (U.S.).
1980	Effective February 17, gas export prices are increased to $4.47/Mcf (U.S.). This price is now higher than residual fuel oil in a number of U.S. markets. In March the Duncan-Lalonde formula for pricing Canadian gas exports is agreed upon between the Canadian and U.S. governments. Under the agreement, export prices will continue to be based on the substitution value of Canadian oil imports although a change in prices will not be made until a $0.15/Mcf (U.S.) change is warranted. The announcement of an impending change will precede its coming into effect by 90 days. The National Energy Program (NEP) is unveiled in October with one of its initiatives allowing the 85 percent Btu equivalence relationship to deteriorate until a 67 percent parity with oil is reached. Under the Program's expected scenario of ever increasing oil prices, the decrease in gas prices relative to oil is to encourage fuel switching from oil to gas.

1981	Effective April 1, export prices are increased to \$4.94 (U.S.) in part to absorb the \$0.30 (Cdn.) Natural Gas and Gas Liquids Tax (NGGLT) levied as part of the NEP. In September, the Federal and Alberta governments sign an agreement on oil and gas pricing and taxation to resolve the differences caused by the unilateral imposition of the NEP by the Federal government. With regard to gas prices, the Federal government agrees to remove the NGGLT on exports and to set the NGGLT on domestic sales such that the Toronto city-gate price will be at 65 percent parity with delivered oil prices.
1982	Despite the prorationing scheme introduced in 1978, TCPL is running into serious financial difficulties with take-or-pay provisions in its producer contracts. Under the TOPGAS Agreement, (signed in September), a group of financial institutions agree to advance producers \$1 billion in prepayments and \$1.3 billion under take-or-pay obligations incurred in the 1980-81 and 1981-82 contract years. In return, the producers agree to further reductions in the take-or-pay provisions of their purchase contracts with TCPL. Another \$320 million is paid to producers under the TOPGAS agreement when TCPL is unable to meet its minimum obligation of 80 percent of daily contract demand in 1982-1983. In return producers agree to a further reduction in TCPL's minimum obligation to 60 percent.
1983	In April, falling oil prices result in the Federal government lowering export prices by \$0.54 (U.S.) to \$4.40 (U.S.) per Mcf. The continuing erosion of natural gas exports because of uncompetitive export prices results in the Federal government introducing the Volume Related Incentive Pricing program (VRIP) in July. Under this program, gas volumes sold in excess of annual established base volumes can be sold at an incentive price of \$3.40/Mcf (U.S.). The base price however, remains at \$4.40/Mcf (U.S.). In November, eligible volumes are allowed to be determined on a monthly rather than annual basis.
1984	The continued poor performance of Canadian exports results in a market responsive gas

export pricing policy. Under the policy, as of November 1 Canadian exporters are free to negotiate market responsive pricing and delivery terms as long as the border price does not fall below the eastern wholesale price (subject to NEB review and Federal government approval).

1985 The Western Accord is signed by the governments of Canada, Alberta, British Columbia and Saskatchewan on March 28. The fundamental motivation for the Accord is to create a more flexible and market-oriented environment for the natural gas and oil industries.

The subsequent October 31 Agreement on Natural Gas Markets and Prices establishes both a framework and timetable for the deregulation of natural gas pricing in Canada. The timetable set for complete deregulation provides for a one year transition period from Nov. 1, 1985 to Oct. 31, 1986 during which wholesale prices prescribed by government are to be frozen. After this time gas prices will be deregulated.

In December, Ontario puts legislation in place requiring provincial distributors to provide transportation service for gas bought directly from producers by industrial users. The distribution toll is to be negotiated between the direct sales purchaser and the distribution company and approved by the Ontario Energy Board (OEB). Failing an agreement, the matter is referred to the OEB which has the power set tolls.

Also in December, Western Gas Marketing Limited (WGML) is formed as wholly owned subsidiary of TCPL whose primary function is the marketing of TCPL's gas supplies. In April 1986 WGML will announce its intention to renegotiate all domestic and export contracts and introduce a netback pricing structure wherein TCPL's producers would receive the net revenue remaining after deducting all transportation, administration, and take-or-pay charges from domestic and export sales revenue.

Effective Nov. 1, producing provinces and the federal government agree to an adjacent border test allowing exports as long as the export price is greater than the domestic price paid in the adjacent region. The NEB is also given authority to approve, by Order, gas export

	contracts with terms of up to 24 months. No volume limitations are to apply to these short-term exports.
Nov. 1, 1985 - Oct. 31, 1986	Twelve month transition period to a fully market sensitive pricing regime during which wholesale prices prescribed by government are frozen but industrial customers without gas sales contracts with LDC's are free to negotiate natural gas prices directly with producers.
May 1986	The NEB revises its surplus determination procedure. The 25A1 reserves formula and deliverability test which had been in effect since 1982 is replaced by a 15-year reserves to production ratio procedure which incorporates estimates of annual reserves additions and forecasts of both Canadian demand and authorized exports. A production capacity check takes the place of the previous deliverability appraisal.
	NEB releases its decision on the availability of transportation services on TCPL. TCPL's tariffs are restructured to enhance the access of direct purchase gas to TCPL's system. In addition, double demand charges paid by direct purchasers are deemed inappropriate and the operating demand volume concept of tariff collection is put into place.
July 1986	The Pipeline Review Panel submits its report finding market sensitive pricing to be feasible for both government and industry by the October 31 deadline. Recommendations made by the panel included support for the sanctity of contracts, contract renegotiations, the separation of marketing and transmission functions within pipeline companies, continuance of the export surplus rule, and support for the option of an end-user bypassing the LDC (subject to the approval of the provincial regulatory body).
Nov. 1, 1986	The federal government announces the end of border pricing tests. The test is replaced by a price monitoring process which will seek to ensure that export prices do not remain below domestic prices for extended periods. Short-term exporters (less than one year) must only supply a provincial removal permit while long-term exporters must have an NEB license and be able to show producer support for newly negotiated prices.

Dec. 1986	The OEB orders the three major Ontario distributors to renegotiate agreements with Western Gas Marketing Limited under which gas entering the province is to be discounted depending on the type of end user. The Board determines that the differential rates usurp its responsibility to set rates and allow the parties to October 31, 1987 to renegotiate.
Jan. 1987	The NEB rules Cyanamid Canada Inc. can build its own pipeline to supply it with natural gas thereby "bypassing" its distributor, Consumers' Gas. The OEB, which had earlier ruled that it had exclusive jurisdiction over local bypass subsequently asked the Ontario Supreme Court to rule which level of government has jurisdiction over such decisions. This court and the Federal Court of Appeals subsequently ruled in Ontario's favour in this matter.
March 1987	The ERCB revises the Alberta surplus rule from the 25A1 surplus test to a 15-year test protecting the supply of the core market; residential, commercial, and small industrial needs. Large industrial users will have to contract for their own security of supply. The OEB orders Ontario's three major distributors to separate their marketing and transportation functions so that all gas consumers can have access to competing sources. Distributors, in effect, are to become transporters of gas and as monopolies, will continue to be regulated by the OEB. They will offer an unbundled array of services for different types of transportation and storage and their sales functions will be put on an equal footing with all other brokers and marketers of gas.
April 1987	A report by the Manitoba Public Utilities Board concludes that there is no competitive gas market for core consumers and that if there was, the average price would be $2.00/Mcf compared to the current average of $2.65/Mcf. The report also suggests that the only solution is to tender for gas for this market. This finding marks the beginning of a 6 month dispute between the Manitoba and Alberta governments. Alberta strongly objects to providing discount gas to the core market and tables legislation in May to allow the provincial cabinet to set the terms of old and new export

permits. The Manitoba government responds by signing long-term supply contracts at a price reported to be below $2.00/Mcf.

The NEB, in a September 25 decision, denies Manitoba's request for access to TCPL's system to deliver directly contracted volumes. The basis for the decision is that the direct sales agreement constitutes a mechanism for self displacement. Soon after, WGML and the provincial distributors reach a new agreement reducing the average sales prices to a reported $2.30/Mcf.

September 1987

The NEB adopts a new procedure, termed the "Market Based Procedure", for determining the surplus of natural gas in Canada available for export. The new procedure does away with the application of a formulaic approach for determining an exportable surplus. Instead the Board will act in two ways to ensure natural gas to be licensed for export is surplus to reasonably forseeable Canadian requirements. The first will be in the context of public hearings which will include three components; (1) a complaints procedure to assess whether Canadian users can obtain additional supplies of gas under similar terms to the export proposal; (2) an export impact assessment to be filed by the applicant; and (3) a public interest determination. The second way will be by monitoring the natural gas supply/demand situation through continued publication of the biennial "Canadian Energy Supply and Demand" study and through periodically published reports called Natural Gas Market Assessments.

December 1987

The Alberta government announces a change in the provincial gas royalty regime. Effective January 1, 1988, the province will determine its royalty share of natural gas production with reference to the Alberta average market price. The province's royalty gas is to be valued at no less than 80 percent of the average market price under this regime. Thus, if a producer elects to sell gas at less than 80 percent of the average price, he must pay royalties based on 80 percent of the price.

Also in December, the Alberta Energy Resources Conservation Board and the Public Utilities Board release the findings of a "Gas Supply and Transportation Service Inquiry." The essential recommendations of the report are that the gas supply requirements of core customers--which were defined as residential, commercial, and small industrial customers--should be protected by long-term commitments for periods of 10 to 15 years. However, these customers can obtain their requirements either by contracting directly with producers or marketers (providing the arrangement is of appropriate term) or through an LDC.

APPENDIX D

DERIVATION OF THE ABOVE-GROUND TO IN-GROUND RATIO

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DERIVATION OF THE ABOVE-GROUND TO IN-GROUND RATIO

The model that is derived below provides a method for calculating the unit revenue that a producer must receive at the wellhead to cover exploration and development costs or any other costs incurred before production begins. Note that if additional development or production costs are required once production begins or if there is a royalty tax, the full cost recovery price increases and the model becomes more complicated. The variables used in the derivation are as follows:

C = present value of capital expenditures
q_o = initial production
R = reserves contained in the discovery
a = q_o/R, a constant describing the rate at which production declines over time
i = discount rate
P_A = wellhead price net of royalties and taxes
P_i = in ground costs, equal to C/R

We assume that the production rate declines exponentially over time as follows:

$$R = \int_0^\infty q_o^{-at} dt \qquad (1)$$

After integration we have,

$$R = -\frac{1}{a} * \left(o - q_o \right) \qquad (2)$$

where $a = q_o/R$

If the wellhead price received by the producer is assumed to be constant over time, the discounted cash flow (DCF) calculation at production start-up is:

$$DCF(p) = \int_0^\infty pe^{-it} q_o e^{-at} dts \; - \; C \qquad (3)$$

This calculation has been greatly simplified. Operating costs are set to zero since they are not part of exploration costs and we have ignored significant tax implications by assuming all costs are expensed (all prices and costs are expressed in real dollars).

After integration equation (3) becomes:

$$DCF(p) = \frac{P_a q_o}{i + a} - C \qquad (4)$$

To determine the price that makes this project profitable, set the DCF equal to zero and obtain

$$P_A = \frac{(i + a)\ C}{q_o} \qquad (5)$$

If we assume that in-ground costs are equal to the capital expenditures divided by reserves (i.e., $P_i = C/R$) and make the substitution $q_o = aR$, we obtain

$$\frac{P_A}{P_i} = 1 + \frac{i}{a} \qquad (6)$$

This relationship states that for the present value costs of discovery and development to be just recovered, the price received at the wellhead must exceed the in-ground cost by a factor related to the discount rate (i) and the decline rate of production (a).

APPENDIX E

SUPPLY COST METHODOLOGY

Appendix E

SUPPLY COST METHODOLOGY

E.1 Capital Costs of Exploration and Development

The methodology used in this study for estimating the full cycle costs of adding natural gas reserves is based on the approach developed by Eglington and Uffelman (1983). Essentially, they estimate the unit cost of finding and developing natural gas reserves as the sum of gas directed exploration and development expenses divided by reserves added through new discoveries, development and re-evaluation (i.e., booked reserves). Exploration expenditures are allocated to oil or gas on the basis of historical intent data obtained from Imperial Oil. Development expenditures are allocated according to the ratio of the number of wells completed for gas or oil to the total number of completions. They also incorporate a lag structure in their cost equations to account for the fact that in many instances, particularly for land and geophysical costs, there is a very distinct period between inital investment and actual discovery.

Our methodology is a considerably simplified version of this approach. Gas directed exploratory and development expenditures are calculated as follows:

$$GEXP_t = EXP_t * EDI_t + DEX_t * DDI_t \qquad (1)$$

Where GEXP = gas directed exploratory and development expenditures in year t
EXP = exploration expeditures (land, geological, geophysical and drilling) in year t
EDI = gas directed exploratory intent in year t
DEV = development expenditures (excluding enhanced recovery and gas plant expenditures) in year t
DDI = gas directed development intent in year t

Unit supply costs (GSUP) are then calculated as follows:

$$GSUP_t = \frac{GEXP_t}{RESADD_t} \qquad (2)$$

where RESADD = reserves additions due to new discoveries, extentions, and revisions in year t .

Canadian Petroleum Association expenditure, drilling and reserves data are used to estimate Canadian supply costs. All expenditures are converted to 1985 ($Cdn.) using CPA cost escalation indices, and to 1985 ($U.S.) assuming an exchange rate of 0.75 $U.S./$Cdn. Gas directed exploratory and drilling intent ratios are estimated as gas well exploratory or development completions divided by total exploratory or development completions. Expenditures on gas plants are excluded from development expenditures because they are accounted for in the treatment of by-products production (See E.2). These data are shown in Tables E.1 through 3.

U.S. supply costs are estimated using U.S. Bureau of Census expenditure data (which is only available to 1983), E.I.A reserves data, and A.P.I. drilling data. All expenditures are converted to 1985 ($U.S.) using the E.I.A.s instantaneous drilling cost index. Gas directed exploratory and development intent ratios are calculated in an analogous fashion. These data are presented in Tables E.4 through 6.

The resulting estimate of supply costs is shown in Tables E.7 and E.8. As noted above, this is a considerably simplified version of Eglinton and Uffleman's methodology in that it first, does not account for time lags in the discovery process and second, because of the arbitrary manner in which gas directed intent ratios are calculated. To assess the impact of time lags in Canadian supply costs, we formulate an equation similar to that employed by Eglington and Uffelman:

$$EXP_t = \left[LAND_{t-3} \times (1+r)^3 \times DDI_{t-3} \right] + \left[GEO_{t-2} \times (1+r)^2 \times DDI_{t-2} \right] + \left[DREX_{t-1} \times (1+r) \times DDI_{t-1} \right] \qquad (3)$$

Where t = the current year

r = the cost of money (which we assume to be 10 percent)

LAND = expenditures on land acquisitions and rentals (CPA category)

Table E.1. CPA Cost Escalation Indices by Expenditure Type

Year	Geological	Exploration and Development Drilling	EOR and Field Equipment	Gas Plant Construction Costs	Total Construction Costs
1970	27.9	19.2	20.6	14.5	19.0
1971	29.9	19.0	22.0	16.4	20.5
1972	31.6	22.1	24.5	18.1	22.6
1973	33.8	25.4	29.2	20.1	25.9
1974	37.4	30.2	37.0	23.0	31.0
1975	46.4	35.6	43.0	27.2	36.7
1976	52.0	40.6	49.4	37.0	43.2
1977	57.3	44.6	55.3	40.6	47.7
1978	66.5	52.1	59.7	59.1	54.2
1979	72.1	62.7	66.9	66.2	62.9
1980	78.0	77.9	73.5	72.9	74.5
1981	84.4	86.2	82.7	82.3	83.5
1982	89.9	89.0	89.7	89.9	89.9
1983	91.6	91.5	91.6	91.6	91.6
1984	95.3	95.2	95.3	95.2	95.2
1985	100.0	100.0	100.0	100.0	100.0

Source: Canadian Petroleum Association, CPA Statistical Handbook 1986 Edition

Table E.2. Alberta Exploration and Development Expenditures (millions of dollars)

	Exploration				Development					
Year	Geological	Drilling	Land	Total	Drilling	Field Equipment	Secondary Recovery	Natural Gas Plants	Other	Total
1970	80.3	83.8	116.6	280.7	72.0	71.2	11.3	162.3	10.9	327.7
1971	63.5	82.8	125.9	272.2	55.5	75.5	19.5	214.0	11.6	376.1
1972	71.2	102.1	124.4	297.7	69.1	107.1	33.6	109.7	13.5	333.0
1973	70.7	131.4	144.3	346.4	101.7	127.4	37.3	65.3	19.0	350.7
1974	112.4	146.5	157.3	416.2	136.4	152.8	23.6	126.1	16.5	455.4
1975	99.0	149.1	207.9	456.0	212.3	181.0	19.9	123.8	25.0	562.0
1976	145.5	236.5	255.5	637.5	277.2	366.2	21.1	155.0	26.1	845.6
1977	223.4	394.7	679.9	1298.0	351.2	298.1	29.0	143.8	39.1	861.2
1978	330.3	644.5	760.5	1735.3	477.4	385.1	51.7	165.9	49.1	1129.2
1979	349.7	1027.5	1144.7	2521.9	679.2	476.3	78.2	204.7	99.9	1538.3
1980	452.3	1621.6	1176.5	3250.4	1063.3	684.1	135.7	241.1	216.5	2340.7
1981	352.2	1543.7	721.3	2617.2	1083.2	782.7	142.9	310.9	98.6	2418.3
1982	325.1	1076.3	465.6	1867.0	942.5	839.6	132.4	493.7	0.0	2408.2
1983	372.7	1017.4	565.1	1955.2	986.3	653.8	59.3	179.7	2.3	1881.4
1984	472.3	1130.3	790.2	2392.8	996.9	681.4	192.9	180.5	84.3	2136.0
1985	480.5	1368.3	1021.1	2869.9	1296.1	902.5	331.0	263.3	87.0	2879.9

Source: Canadian Petroleum Association, CPA Statistical Handbook 1986 Edition

Table E.3. Canadian Exploration and Development Intent Ratios

Year	Number of Gas Well Exploratory Completions	Total Number of Exploratory Completions	Exploratory Intent Ratio	Number of Gas Well Development Completions	Total Number of Development Completions	Development Intent Ratio
1970	209	267	0.439	414	661	0.626
1971	228	339	0.402	469	723	0.649
1972	318	387	0.451	692	1137	0.609
1973	476	585	0.449	1042	1533	0.680
1974	448	530	0.458	1271	1840	0.691
1975	504	585	0.463	1454	2043	0.712
1976	1056	1168	0.475	2388	2849	0.838
1977	1024	1202	0.460	2309	2876	0.803
1978	999	1235	0.447	2331	3070	0.759
1979	977	1278	0.433	2239	3194	0.701
1980	1296	1696	0.433	2672	3911	0.683
1981	1001	1498	0.419	2004	3070	0.653
1982	689	1114	0.382	1810	3004	0.603
1983	375	801	0.319	813	2844	0.286
1984	461	1079	0.299	936	2934	0.319
1985	439	1100	0.271	1578	3986	0.396

Source: Canadian Petroleum Association, CPA Statistical Handbook 1986 Edition

Table E.4. U.S. Cost Escalation Index

Year	Instantaneous Drilling Cost Index	1985=100
1973	80	0.58
1974	85	0.62
1975	91	0.66
1976	100	0.73
1977	108.7	0.79
1978	121.9	0.89
1979	141.2	1.03
1980	176.9	1.29
1981	203.6	1.48
1982	163.8	1.19
1983	141.5	1.03
1984	146.4	1.06
1985	137.6	1.00

Source: U.S. D.O.E, E.I.A., Indexes and Estimates of Domestic Well Drilling Costs 1984 and 1985, (Washington D.C.: D.O.E/E.I.A)

Table E.5. U.S. Exploration and Development Expenditures (millions of dollars)

Year	Exploration	Development
1973	5446.2	3039.3
1974	8658.8	4413.1
1975	5310.3	6422.6
1976	7183.9	7734.8
1977	7794.9	9212.9
1978	9637.9	11010.7
1979	15617.2	17303.6
1980	20830.8	19578.9
1981	30674.2	25015.7
1982	27858.3	25858.8
1983	21737.0	26500.0

Source: U.S. Department of Commerce, Bureau of Census: Annual Survey of Oil and Gas

Table E.6. U.S. Exploration and Development Intent Ratios

Year	Number of Gas Well Exploratory Completions	Total Number of Exploratory Completions	Exploratory Intent Ratio	Number of Gas Well Development Completions	Total Number of Development Completions	Development Intent Ratio
1973	1079	1733	0.623	5896	15493	0.381
1974	1205	2075	0.581	5963	18757	0.318
1975	1261	2252	0.560	6908	22896	0.302
1976	1361	2461	0.553	8077	24674	0.327
1977	1557	2738	0.569	10562	28081	0.376
1978	1786	2975	0.600	12619	30495	0.414
1979	1921	3256	0.590	13245	32599	0.406
1980	2085	3862	0.540	15047	45390	0.332
1981	2522	5183	0.487	17220	57079	0.302
1982	2172	4653	0.467	16638	53409	0.312
1983	1654	3783	0.437	12851	48118	0.267

Source: American Petroleum Institute, Basic Petroleum Data Book, September 1986

Table E.7. Canadian Supply Costs

Year	Gas Directed Exploration Expenditures (\$ 1985 Cdn)	Gas Directed Development Expenditures (\$ 1985 Cdn)	Reserve Additions (Tcf)	Unit Supply Costs	Three Year Moving Average
				(\$ 1985 U.S. per Mcf)	
1970	587.5	432.3	1.588	0.48	
1971	499.1	396.0	3.397	0.20	
1972	558.3	457.9	1.592 *	0.48	0.39
1973	575.9	588.7	2.162	0.40	0.36
1974	592.3	629.2	3.585	0.26	0.38
1975	554.0	725.1	3.904	0.25	0.30
1976	713.7	1200.0	2.453	0.59	0.36
1977	1242.2	1059.6	2.730	0.63	0.49
1978	1399.7	1153.4	4.524	0.42	0.55
1979	1700.6	1302.5	5.639	0.40	0.49
1980	1834.3	1747.0	2.696	1.00	0.61
1981	1287.6	1526.7	4.252	0.50	0.63
1982	794.1	1194.4	2.293	0.65	0.71
1983	681.0	487.6	2.618	0.33	0.49
1984	752.2	590.3	7.964	0.13	0.37
1985	778.2	904.0	0.041	30.96	10.47

Source: CERI

* Reserve additions for 1972 are calculated as the sum of discoveries and extensions because large negative revisions resulted in negative gross reserve additions

Table E.8. U.S. Supply Costs

Year	Gas Directed Exploration Expenditures (\$ 1985 U.S.)	Gas Directed Development Expenditures (\$ 1985 U.S.)	Reserve Additions (Tcf)	Unit Supply Costs	Three Year Moving Average
				(\$ 1985 U.S. per Mcf)	
1973	5832.4	1134.4	6.824	1.02	
1974	8140.0	1067.9	8.678	1.06	
1975	4496.2	1027.4	10.482	0.53	0.87
1976	5466.7	1100.5	7.556	0.87	0.82
1977	5611.2	1303.6	13.240	0.52	0.64
1978	6531.2	1389.6	19.425	0.41	0.60
1979	8979.0	1289.2	12.221	0.84	0.59
1980	8747.6	995.8	16.723	0.58	0.61
1981	10007.4	1056.0	21.446	0.52	0.65
1982	10924.1	1217.7	17.297	0.70	0.60
1983	9241.9	902.5	14.523	0.70	0.64
1984	0.0	0.0	14.409	0.00	
1985	0.0	0.0	11.891	0.00	

Source: CERI

GEO = geological and geophysical expenditures
DREX = exploratory drilling expenditures

Then $GEXP_t = EXP_t + DEV_t$ (4)

and $GSUP_t = GEXP_t/RESADD_t$ (5)

The sensitivity of Canadian supply costs to the intent ratio is examined utilizing an assumption made by Janice Pasay (1986). This is that since most exploration drilling has traditionally been directed towards oil, the exploratory gas intent ratio is estimated as (1-1.25 * Exploratory Oil Intent). The results of these two sensitivities are provided in Table E.9 along with the original estimates. As expected, lower gas intent ratios result in considerably lower supply costs. The lag structure results in slightly higher costs primarily because of the cost of money. For example, the present value of expenditures made 3 years ago is $(1 + r)^3$ times the original investment. In general the estimated supply costs are not that sensitive to changes in expenditures. They are, however, extremely sensitive to the gas intent assumptions and to the reserves data. Although the paucity of U.S. data prevented similar analysis, one would expect that alternative assumptions would have a comparable impact.

E.2 Capital Costs of Gas Plant Construction

In our treatment of natural gas by-products production it was necessary to account for the capital costs of gas plant construction. As noted in E.1, these expenditures were excluded from the estimate of supply costs for this reason. Essentially, the capital costs of gas plant construction are estimated in terms of natural gas reserves added in the same year (just as they would have been had we included them in development expenditures in E.1). However, to arrive at an estimate of the net value of by-product production, it is necessary to convert this in-ground cost to an above-ground cost using the methodology described in section 3.2 and Appendix D.

Table E.10 presents the various components of this calculation. In-ground costs are estimated as annual expenditures on gas plant construction divided by natural gas reserves additions. The decline factor (a) is estimated as annual natural gas liquids production divided by established natural gas liquids reserves at year end. The above-ground to in-ground ratio is estimated as $(1 + i/a)$, where i

Table E.9. Sensitivity Analysis of Canadian Supply Costs
($ 1985 Cdn)

Year	Original Costs	With Lagged Expenditures	Gas Exploratory Intent Ratio Calculated as (1 - 1.25*Oil Exploratory Intent)
1970	0.64		0.56
1971	0.26		0.22
1972	0.64		0.56
1973	0.54	0.60	0.47
1974	0.34	0.37	0.29
1975	0.33	0.37	0.30
1976	0.78	0.80	0.72
1977	0.84	0.71	0.75
1978	0.56	0.49	0.49
1979	0.53	0.47	0.45
1980	1.33	1.29	1.11
1981	0.66	0.78	0.55
1982	0.87	1.19	0.73
1983	0.45	0.59	0.31
1984	0.17	0.18	0.11
1985	41.28	41.26	28.45

Source: CERI

Table E.10. Above-ground costs of Natural Gas Plant Construction Expenditures

Year	Natural Gas Plants ($ millions 1985)	Natural Gas Reserve Additions (Tcf)	In-ground Costs ($ 1985 Cdn)	Decline Factor	Above-Ground to In-ground Ratio	Above-ground Costs ($ 1985 Cdn)
1970	162.3	1.588	0.10	0.044	3.285	0.34
1971	214.0	3.397	0.06	0.052	2.924	0.18
1972	109.7	1.592	0.07	0.066	2.519	0.17
1973	65.3	2.162	0.03	0.075	2.339	0.07
1974	126.1	3.585	0.04	0.070	2.431	0.09
1975	123.8	3.904	0.03	0.070	2.434	0.08
1976	155.0	2.453	0.06	0.070	2.419	0.15
1977	143.8	2.730	0.05	0.079	2.268	0.12
1978	165.9	4.524	0.04	0.057	2.758	0.10
1979	204.7	5.639	0.04	0.065	2.546	0.09
1980	241.1	2.696	0.09	0.065	2.550	0.23
1981	310.9	4.252	0.07	0.063	2.593	0.19
1982	493.7	2.293	0.22	0.058	2.738	0.59
1983	179.7	2.618	0.07	0.052	2.940	0.20
1984	180.5	7.964	0.02	0.057	2.754	0.06
1985	263.3	0.041	6.46	0.046	3.152	20.36

Source: CERI

is equal to the rate of discount which we assumed to be 10 percent. The resultant above-ground cost represents the capital charge component of natural gas processing fees. This measure reflects the volatile nature of annual natural gas reserves additions and varies correspondingly (especially for 1985). On average, when combined with plant operating costs, it falls in the range of customer processing fees charged by the various plant operators in Alberta. These fees range from $0.20 per Mcf to over $1.00 per Mcf depending on the age of the plant, the region and if there is sulphur in the gas.

APPENDIX F

SUPPLY AND DEMAND PROFILES OF SOME MAJOR U.S. LDCs

Appendix F

SUPPLY AND DEMAND PROFILES OF SOME MAJOR U.S. LDCs

U.S. LDCs in those regions having access to Canadian natural gas represent an important growth market for future export sales. Although improved access to U.S. pipelines is required for Canadian marketers and producers to effectively serve these markets, in a tighter U.S. gas market these LDCs will increasingly look to Canadian gas supplies as a secure and viable addition to their supply protfolio. The following discussion briefly examines the different markets served by some major U.S. LDCs having access to Canadian gas as well as their principal sources of supply.[1]

F.1 Pacific Region

There are five important distribution companies in this region; the Southern California Gas Company, Pacific Gas and Electric Company, Northwest Natural Gas Company, Washington Natural Gas Company, and Cascade Natural Gas Company (see Table F.1).

The Southern California Gas Company (SoCal) is the largest gas utility in the U.S. and serves mainly the Los Angeles area. It purchases gas from three interstate suppliers, allowing some flexibility in its purchasing practises. SoCal tends to concentrate its sales in the residential and electric utility sectors. This is due in no small part to the regulatory initiatives of the California Public Utilities Commission (CPUC), which is one of the PUCs which has succeeded in inverting the rate schedule. Residential, commercial, and electricity generation demands are given highest priority and therefore receive SoCal's lowest cost sources of gas, while industrial users must pay for higher priced increments of gas. The result is that gas has reached a 97 percent saturation level in the space heating market, while industrial gas sales have lost share to residual fuel oil. The Pacific Gas and Electric Company (P.G. & E.) purchases from two suppliers and its sales are concentrated similarily to SoCal's for much the same reasons.

TABLE F.1
PACIFIC REGION
(Bcf)

Supply/Demand Characteristics	Southern California Gas Company (SOCAL)		Pacific Gas and Electric Company (P.G. & E.)		Northwest Natural Gas Co.	
Supply Profile, 1986 Purchases	California Producers	52.5 (5.9%)	El Paso Natural Gas Co.	95.9 (28.4%)	Northern Pipeline Co.	60.5 (100.0%)
	El Paso Natural Gas Co.	461.7 (52.1%)	Pacific Gas Transmission Co.	241.9 (71.6%)	TOTAL	60.5
	Pacific Intrastate Co.	30.4 (3.4%)	TOTAL	337.8		
	Spot Market	123.0 (13.9%)				
	Transwestern Pipeline Co.	218.8 (24.7%)				
	TOTAL	886.4				
Demand Profile, 1985-1986 Deliveries	Commercial	96.9 (11.0%)	Commercial	116.3 (15.8%)	Commercial	14.1 (23.3%)
	Industrial	138.6 (16.3%)	Industrial	137.3 (18.7%)	Industrial	29.3 (48.3%)
	Residential	279.7 (32.3%)	Residential	208.6 (28.4%)	Residential	17.2 (28.4%)
	E. Utility	335.2 (39.4%)	E. Utility	273.6 (37.2%)	E. Utility	0.0
	Other	0.0	Other	0.0	Other	0.0
	TOTAL	830.4	TOTAL	735.8	TOTAL	60.6

TABLE F.1 (Continued)

Supply/Demand Characteristics	Washington Natural Gas Co.		Cascade Natural Gas. Co.		
Supply Profile, 1986 Purchases	Northwest Pipeline Co.	55.1 (87.9%)	Northwest Pipeline Co.	23.6 (63.6%)	
	Various Suppliers	7.6 (12.1%)	Various Suppliers	13.5 (36.4%)	
	TOTAL	62.7	TOTAL	37.1	
Demand Profile, 1985-1986 Deliveries	Commercial	20.3 (32.4%)	Commercial	8.8 (23.8%)	
	Industrial	19.2 (30.7%)	Industrial	23.2 (62.8%)	
	Residential	23.1 (36.9%)	Residential	4.9 (13.3%)	
	E. Utility	0.0	E. Utility	0.0	
	Other	0.0	Other	0.0	
	TOTAL	62.6	TOTAL	36.9	

The Northwest Natural Gas Company (Northwest Natural) purchases the bulk of its supply from Northwest Pipeline and serves mainly the industrial sector of the Portland, Oregon area. Industrial sales made up about 48 percent of total sales in 1986. Large swings in industrial sales (total sales declined 16 percent in 1983 due to fuel switching and a mild winter) are due to stiff competition from residual fuel oil. The Washington Natural Gas Company (Washington Natural) serves Seattle and Olympia in Washington, and purchases all of its gas from Northwest Pipeline. Until recently, Washington Natural faced competition in all sectors, most notably in the industrial sector from high sulphur residual fuel oil. Washington Natural was constrained to a 59 percent capture rate in the residential sector, but the recent firming up of electricity prices has allowed an increase of this figure to an 80 percent capture rate on new residential stock in 1984.

The Cascade Natural Gas Company (Cascade Natural) also purchases all of its supplies from Northwest Pipeline and serves mainly small, one-industry towns in Washington State. Low electricity prices have constrained sales in the residential and commercial sectors, while some load loss to coal has been experienced in the food processing (industrial) sector. Industrial sales made up 63 percent of total sales in 1986 and are expected to continue to maintain this share in total gas sales.

F.2 West North Central Region

Northern States Power (Northern States) sells most of its gas in Minnesota (see Table F.2). Approximately 71 percent of total sales in 1985 were concentrated in the residential and commercial sectors. Natural gas has a price advantage in all sectors in this region. This has resulted in stable sales figures for Northern States over the past five years. Northern States purchases nearly all of its supply from Northern Natural. The Iowa Public Service Company (Iowa Public Service) also purchases the bulk of its gas from one supplier, Northern Natural. The farm economy in this region is not expected to recover quickly, leading to private company forecasts of flat sales over the next few years. Industrial sales are mainly to one customer and accounted for about 47 percent of total sales in 1985.

The Peoples Natural Gas Company Division of Internorth Incorporated (Peoples Natural) is affiliated with Northern Natural and not suprisingly purchases the majority of its gas from Northern. However, it also purchases gas from ten other pipelines, as well as more than 500 wellheads. As in most of the West North Central region, the recession has prevented sales growth in the residential and commercial sectors even though gas is very price competitive and maintains a high capture rate in those sectors. Although the industrial sector held about 55 percent share of total gas deliveries in 1986, Peoples Natural faces strong competition from residual fuel oil in the industrial sector because of high gas prices in this sector. Incentive plans to industrial customers with dual fuel capabilities have been put in place in an attempt to regain the load lost to residual fuel oil.

Minnegasco Incorporated (Minnegasco) serves mainly the Minneapolis area of Minnesota. The utility purchases gas primarily from a single source, Northern Natural, although it has been proposed to connect Midwestern, which carries very competitively priced Canadian gas and is within 50 miles of Minneapolis, into Minnegasco's system. Since Minnesota is an urban area, Minnegasco's sales are mainly in the residential sector (46 percent of total sales). In the industrial sector, Minnegasco offers incentive plans for interruptible users.

TABLE F.2
WEST NORTH CENTRAL
(Bcf)

Supply/Demand Characteristics	Northern States Power Co. and Subsidiaries (Northern State Power Company of Wisconsin and Lake Superior District Power Company)		Iowa Public Service Co.		Peoples Natural Gas Co.	
Supply Profile, 1986 Purchases	Midwestern	6.9 (9.0%)	Northern Natural Gas Co.	34.0 (100.0%)	Colorado Interstate Gas Co.	2.5 (4.5%)
	Northern Natural Gas Co.	69.9 (91.0%)	TOTAL	34.0	Great Lakes Gas Transmission	0.6 (1.1%)
	TOTAL	76.8			KN Energy Inc.	1.3 (2.3%)
	Note: These are 1984 purchases.				Midwestern	0.6 (1.1%)
					Natural Gas Pipeline Company of America	0.4 --
					Northern Natural	47.2 (82.7%)
					Williams Natural Gas Co.	3.4 (6.0%)
					TOTAL	56.1
Demand Profile, 1985-1986 Deliveries	Commercial	21.4 (29.0%)	Commercial	7.4 (19.6%)	Commercial	20.2 (17.2%)
	Industrial	20.0 (27.0%)	Industrial	17.7 (46.9%)	Industrial	64.1 (48.3%)
	Residential	33.1 (44.0%)	Residential	12.5 (33.4%)	Residential	31.5 (28.4%)
	E. Utility	0.0	E. Utility	0.26 (--)	E. Utility	1.76 (1.5%)
	Other	0.0	Other	0.0	Other	0.0
	TOTAL	74.5	TOTAL	37.8	TOTAL	117.6

TABLE F.2 (Continued)

Supply/Demand Characteristics	Minnegasco Inc.			
Supply Profile, 1986 Purchases	KN Energy Inc.	5.3 (3.5%)		
	Northern Natural Gas Co.	145.6 (96.5%)		
	TOTAL	150.9		
Demand Profile, 1985-1986 Deliveries	Commercial	33.1 (22.0%)		
	Industrial	48.2 (32.0%)		
	Residential	68.9 (45.8%)		
	E. Utility	0.4 —		
	Other	0.0		
	TOTAL	150.6		

.3 East North Central Region

Northern Indiana Public Service (Northern Indiana) purchases as from five interstate pipelines and thus enjoys considerable gas-to-as competition between these sources and has good flexibility in its urchasing decisions (see Table F.3). The utility distributes gas in he heavy industrial area of the East North Central region and as a esult, concentrates sales to the industrial sector which, in 1986, ccounted for 50 percent of total sales.

Consumers Power Company and Subsidiary (Consumers Power) has hree sources of supply but the highest cost supply, Trunkline Gas, ccounted for 50 percent of total supply in 1986. Although Consumers ower services the automotive industry in Michigan, most sales (56 ercent) are to the residential sector. Even though Consumers Power as enjoyed a 95 percent capture rate in this sector, natural gas and lectricity prices have begun to converge, making future competition rom electricity likely. High cost gas supplies and a very high istribution margin for interruptible gas (about $0.85 per Mcf in 1985) ave resulted in considerable interfuel competition from residual fuel il.

Michigan Consolidated Gas Company (Michcon) services Detroit d enjoys a wide range of suppliers, including spot market purchases ichcon has extensive storage facilities) from both U.S. and Canadian urces. A declining population in Detroit has led to a 12 percent op in end use sales between 1981 and 1984. The decline has been enly split between the space heating and industrial markets. The rgest share of sales (48 percent of total 1986 sales) is to the sidential sector. Residential sales are expected to drop by 2 rcent annually over the next few years due to the falling population se and continued conservation. In the industrial sector, residual el oil and coal are very price competitive relative to natural gas.

The East Ohio Gas Company (East Ohio) service area includes the ties of Cleveland and Akron, Ohio. The utility purchases gas from o suppliers but is effectively prohibited from making spot market rchases because of contractual obligations to its owner and main pplier, Consolidated Gas Company. Industrial gas sales have declined e to the general decline in the steel industry and a movement towards rect gas purchases by large industrial customers. Residential sales counted for about 63 percent of total 1986 sales and are expected to

TABLE F.3
EAST NORTH CENTRAL
(Bcf)

Supply/Demand Characteristics	Northern Indiana Public Service Co.		Consumers Power Company		Michigan Consolidated Gas Company	
Supply Profile, 1986 Purchases	ANR Pipeline Co.	1.0 --	Local Producer	46.3 (19.5%)	ANR Pipeline Co.	164.9 (51.2%)
	Midwestern	63.3 (35.0%)	Northern Michigan Exploration	1.2 —	Great Lakes	5.0 (1.6%)
	Natural Gas Pipeline Co. of America	69.1 (38.2%)	Panhandle Eastern	52.5 (22.1%)	Local Producer	63.4 (19.7%)
	Panhandle Eastern	21.6 (12.0%)	Spot Market	21.1 (8.9%)	Panhandle Eastern	4.2 (1.3%)
	Spot Market	21.8 (12.1%)	Trunkline Gas Co.	116.6 (49.1%)	Producer	81.5 (25.3%)
	Trunkline Gas Co.	3.9 (2.2%)			Storage	2.9 (1.0%)
	TOTAL	180.7	TOTAL	237.7	TOTAL	321.9
Demand Profile, 1985-1986 Deliveries	Commercial	25.2 (14.2%)	Commercial	57.4 (20.9%)	Commercial	73.3 (23.8%)
	Industrial	88.5 (49.9%)	Industrial	40.0 (14.6%)	Industrial	83.2 (27.0%)
	Residential	63.4 (35.7%)	Residential	154.1 (56.2%)	Residential	147.4 (47.9%)
	E. Utility	.25 —	E. Utility	0.0 —	E. Utility	3.3 (1.0%)
	Other	0.0 —	Transport	19.6 (7.1%)	Transport	0.6 —
			Other	3.2 (1.2%)	Other	0.0 —
	TOTAL	177.4	TOTAL	274.3	TOTAL	307.8

TABLE F.3 (Continued)

Supply/Demand Characteristics	Wisconsin Gas Company		Indiana Gas Company		Northern Illinois Gas Co.	
Supply Profile, 1986 Purchases	ANR Pipeline Co.	80.0 (80.2%)	ANR Pipeline Co.	0.1	Midwestern	64.2 (22.1%)
	Midwestern	1.2 (1.2%)	Entrade Corp.	0.7 (1.1%)	Natural Gas Pipeline Co. of America	195.2 (45.7%)
	Northern Natural	8.9 (8.9%)	Panhandle Eastern	39.5 (60.7%)	Northern Natural.	31.4 (7.4%)
	Wisconsin Gas Co.	9.7 (9.7%)	Texas Gas	19.8 (30.4%)	Panhandle Eastern	0.0005 —
			Various Suppliers	5.0 (7.7%)		
	TOTAL	99.8	TOTAL	65.1	TOTAL	290.8
Demand Profile, 1985-1986 Deliveries	Commercial	15.3 (14.6%)	Commercial	17.6 (26.5%)	Commercial	113.9 (26.7%)
	Industrial	41.8 (39.8%)	Industrial	16.6 (25.0%)	Industrial	129.6 (30.4%)
	Residential	42.4 (40.4%)	Residential	32.2 (48.5%)	Residential	182.6 (42.8%)
	E. Utility	0.0	E. Utility	0.0 --	E. Utility	0.6 —
	Other	5.5 (5.2%)	Other	0.0 —	Other	0.0 —
	TOTAL	105.0	TOTAL	66.4	TOTAL	426.7

TABLE F.3 (Continued)

Supply/Demand Characteristics	Peoples Gas Light and Coke Co.		Wisconsin Natural Gas Co.		East Ohio Gas Co.	
Supply Profile, 1986 Purchases	Midwestern	14.6 (6.1%)	ANR Pipeline Co.	51.9 (100%)	Appalachian Producers	51.0 (23.1%)
	Natural Gas Pipeline Co. of America	165.1 (68.6%)			CNG Development Co.	2.3 (1.0%)
	Various Suppliers	60.9 (25.3%)			Consolidated Gas	87.5 (39.7%)
					Panhandle Trading Co.	26.4 (12.0%)
					Panhandle Eastern	14.7 (6.7%)
					Tennegasco Corp.	38.4 (17.4%)
	TOTAL	240.6			TOTAL	220.3
Demand Profile, 1985-1986 Deliveries	Commercial	56.3 (22.3%)	Commercial	8.2 (13.3%)	Commercial	50.2 (23.3%)
	Industrial	41.4 (16.4%)	Industrial	27.3 (44.2%)	Industrial	30.4 (14.1%)
	Residential	150.5 (59.7%)	Residential	24.0 (38.8%)	Residential	135.2 (62.7%)
	E. Utility	3.9 (1.5%)	E. Utility	0.0 —	E. Utility	0.0 —
	Other	0.0 —	Other	2.3 —	Other	0.0 —
	TOTAL	252.1	TOTAL	61.8	TOTAL	215.8

remain flat in the near future. Both residential and commercial markets are similar to other East North Central markets in that while a high saturation rate has been achieved, little or no growth is expected.

The Wisconsin Natural Gas Company (Wisconsin Natural) is contracted to one high cost supplier, ANR Pipeline, until 1992. Wisconsin Natural's service area has been economically depressed due to general decline in the regions heavy industry sector. Industrial gas sales have decreased to rough equivalence (about 40 percent of total 1986 sales) with the residential sector. Incentive plans for dual fuel customers are expected to recoup some of the recent losses.

The Indiana Gas Company (Indiana Gas) serves mainly smaller cities and towns in the East North Central region and has considerable purchasing flexibility from a number of suppliers. The company's sectoral sales profile is typical of East North Central utilities, with the majority of sales occuring in the residential sector (about 49 percent of total 1986 sales). The slump in the automotive and steel related industrial sectors has accounted for almost all of the 10 Bcf decline in sales between 1981 and 1984. Strong competition from residual fuel oil and coal has prompted Indiana Gas to set up a subsidiary to broker gas for large industrial customers and to provide transportation sevices.

The Peoples Gas, Light and Coke Company (Peoples) serves Greater Chicago and purchases gas from two interstate pipelines as well as on the spot gas market. Since Peoples' service area is metropolitan, most gas sales (60 percent of total 1986 sales) are concentrated in the residential sector. Conservation is the main determinant of future sales in both the residential and commercial sectors, since high saturation rates have been achieved in both. Peoples' expectation is that the decline in industrial gas sales (23 percent between 1981 and 1984) will continue in the future due to sectoral decline in old-line manufacturers and interfuel competition.

The Northern Illinois Gas Company (N. Illinois) has good flexibility in gas purchase decisions as gas can be purchased from four alternative sources. End use sales have fallen by only 2.5 percent between 1981 and 1984, mainly due to structural differences vis-a-vis the rest of the East North Central economy. The largest industrial customers have been the relatively stable chemical producers. The residential sector accounted for 43 percent of total 1986 sales, with new additions outpacing conservation efforts. Industrial sales are expected to pick up, while conservation is likely to result in flat residential and commercial sales.

The Wisconsin Gas Company (Wisconsin Gas) has a service area which includes the city of Milwaukee, and purchases most of its supplies from three sources. The residential sector accounted for about 40 percent of total 1986 sales, and a high saturation rate leads to expectations of low sales growth as conservation is expected to offset new housing starts. The industrial sector, comprised mainly of pulp and paper and brewery companies, has about the same share in total sales as the residential sector and has shown growth in sales of about 5 per cent between 1981 and 1984.

F.4 The New England/Middle Atlantic Region

The Boston Gas Company (Boston Gas) has a service area that includes Greater Boston, and purchases most of its gas from two interstate pipelines (see Table F.4). In the residential sector (about 36 percent of total 1986 sales), fuel oil provides some competition but new customer additions are expected to offset conservation in the near term. The commercial sector has experienced growth in small building construction where fuel oil cannot afford larger user discounts. Gas sales are expected to grow correspondingly over the next few years. Gas does not compete well in the industrial sector because of its high price and accounted for only 11 percent of 1986 total sales. It is, however, used extensively for electricity generation which, in 1986, accounted for 31 percent of total sales.

The Public Service Electric and Gas Company (Public Service) has a service area that includes Newark and Jersey City. The utility enjoys great flexibility in gas purchases. This is due in part to the extensive storage facilities which allow Public Service to take advantage of interruptible sales and spot sales of natural gas in lieu of firm supplies during the summer, and in part to the company's ability to purchase its supplies from four major interstate pipelines. Demand growth has been limited by supply and gas sales have grown only as firm supply becomes available. The residential and commercial sectors, which accounted for 48 and 30 percent of total 1986 sales respectively, are expected to experience continued growth. The capture rate in the residential sector is 95 percent, so that the 50 percent saturation rate can be expected to increase over time. The industrial and electric utility sectors, which accounted for 22 percent of 1984 total sales, face strong competition from residual fuel oil. However, a significant amount of the areas generation capacity relies solely on fuel oil and could easily be converted to dual-fired facilities.

The National Fuel Gas Company (National) services an area which includes Buffalo, New York and Erie, Pennsylvania. The utility is affiliated with the National Fuel Company and purchases gas from an array of suppliers, including Canadian gas through Niagara. Most of National's sales are concentrated in the residential sector (about 56 percent of total 1986 sales). Unlike most Middle Atlantic distributors, National's service area has not suffered from supply limitation or high supply prices because it has access to a number of interstate

TABLE F.4
NEW ENGLAND/MID ATLANTIC
(Bcf)

Supply/Demand Characteristics	Boston Gas Company			Consolidated Edison			Brooklyn Union		
Supply Profile, 1986 Purchases	Algonquin Gas	56.3	(58.7%)	Algonquin Gas	0.9	—	Consolidated Gas	2.1	(1.8%)
	Distrigas of Massachusett	13.7	(13.9%)	Consolidated Gas	2.3	(1.2%)	Consumers Gas Co.	1.7	(1.5%)
	Sea-3 Inc.	0.07	—	Energy Marketing Exchange	1.3	—	Distrigas of Massachusetts	12.7	(10.8%)
	Tennessee Gas	25.9	(27.9%)	Koch Hydrocarbon Co.	1.1	—	Exxon USA	0.6	—
				National Fuel Gas Supply	5.3	(2.8%)	Getty Synthetic Fuel	1.1	(1.0%)
				Northwest Central	1.4	—	Producer	3.8	(3.2%)
				Own Supply	1.4	—	Spot Gas	25.2	(21.5%)
				Panhandle Eastern	4.3	(2.2%)	Tennessee	7.6	(6.4%)
				Producers Gas Co.	0.7	—	Texas Eastern	16.0	(13.7%)
				Sulpetro	0.5	—	Transcontinental	46.3	(39.5%)
				Tennessee	13.2	(6.9%)			
				Texas Eastern	42.3	(22.0%)			
				TransAmerican	5.2	(2.7%)			
				Transco Exploration Co.	2.9	(1.5%)			
				Transcontinental	109.9	(57.0%)			
	TOTAL	95.9		TOTAL	192.7		TOTAL	117.1	
Demand Profile, 1985-1986 Deliveries	Commercial	21.9	(22.2%)	Commercial	32.0	(32.8%)	Commercial	12.5	(11.9%)
	Industrial	10.8	(10.9%)	Industrial	4.4	(4.5%)	Industrial	8.0	(7.6%)
	Residential	35.6	(36.1%)	Residential	44.5	(45.6%)	Residential	78.2	(74.3%)
	E. Utility	30.4	(30.8%)	E. Utility	10.1	(10.4%)	E. Utility	0.0	
	Other	0.0		Other	6.5	(6.6%)	Other	6.5	(6.2%)
	TOTAL	98.7		TOTAL	97.5		TOTAL	105.2	

TABLE F.4 (Continued)

Supply/Demand Characteristics	Long Island Lighting			National Fuel Gas Company			New Jersey Natural Gas Company		
Supply Profile, 1986 Purchases	Consolidated Gas	0.4	—	National Fuel Gas Supply	147.8	(95.7%)	Algonquin Gas	1.4	(2.7%)
	Energy Marketing Exchange	2.6	(3.3%)	Tennessee		(30.0%)	Consumers Gas Co.	1.5	(2.9%)
	Own Supply	1.8	(2.3%)	Texas Eastern		(15.0%)	Equitable Consolidated	5.3	(10.2%)
	Panhandle	2.1	(2.7%)	Consolidated Gas		(17.0%)			
	Shell Oil Co.	0.2	—	Transcontinental		(2.0%)	Own Supply	0.7	(1.4%)
	Sulpetro	0.4	—				Texas Eastern	42.0	(81.6%)
	Tennessee	2.1	(2.7%)	Producer	6.6	(4.3%)	Transcontinental	0.6	(1.2%)
	Texas Eastern	13.5	(17.1%)						
	Transcontinental	55.9	(70.8%)	TOTAL	134.4		TOTAL	51.5	
	TOTAL	79.0		Note: National Fuel Gas Co. purchases all of its supply from its affiliate National Fuel Gas Supply.					
Demand Profile, 1985–1986 Deliveries	Commercial	11.8	(14.7%)	Commercial	31.6	(20.5%)	Commercial	6.0	(12.0%)
	Industrial	3.8	(4.7%)	Industrial	35.6	(23.1%)	Industrial	6.9	(13.8%)
	Residential	32.4	(40.4%)	Residential	86.2	(56.0%)	Residential	24.7	(49.6%)
	E. Utility	29.6	(36.9%)	E. Utility	0.5		E. Utility	12.2	(24.5%)
	Other	2.6	(3.2%)	Other	0.0		Other		
	TOTAL	80.2		TOTAL	153.9		TOTAL	49.8	

TABLE F.4 (Continued)

Supply/Demand Characteristics	Public Service Electric and Gas			
Supply Profile, 1986 Purchases	Consolidated Gas	4.1 (1.8%)		
	Exxon U.S.A.	8.3 (3.0%)		
	Gulf South Corp.	6.1 (2.2%)		
	National Fuel Gas Supply	5.1 (1.9%)		
	Pendle Eastern	10.6 (3.9%)		
	Producer	26.7 (9.7%)		
	Tennessee	15.5 (5.6%)		
	Texas Eastern	111.8 (40.7%)		
	TransAmerican Natural Gas	7.0 (2.5%)		
	Transcontinental	78.5 (28.6%)		
	TOTAL	274.9		
Demand Profile, 1985-1986 Deliveries	Commercial	63.4 (29.8%)		
	Industrial	46.8 (22.0%)		
	Residential	102.0 (48.0%)		
	E. Utility	0.2 —		
	Other	0.2 —		
	TOTAL	212.6		

pipelines. Therefore, the growth potential for National is not as high as for other distribution companies in the Middle Atlantic regions. Saturation rates for both the residential and industrial sectors are high, while some growth can be expected in the commercial sector.

The Consolidated Edison Company of New York, Incorporated (Consolidated) serves New York City and has a very diversified natural gas supply portfolio. The utility currently purchases gas from five interstate pipelines and obtains significant supplies on the spot market during the summer months. As with most Middle Atlantic distributors, Consolidated's sales have been constrained by supply and prices. Consolidated is concentrating its efforts on the residential sector where natural gas enjoys a price advantage over other fuels. In this sector, the saturation rate for gas is only 45-50 percent but the capture rate on new housing is 90 percent in Consolidated's service area.

The Long Island Lighting Company (Long Island) services the area of Long Island. The utility purchases the bulk of its supplies from two sources, Transcontinental and Texas Eastern. The service area is mainly residential and commercial with about 55 percent of 1986 sales being destined for the space heating market. A significant share of gas sales, about 37 percent in 1986, is directed towards electricity generation.

The Brooklyn Union Gas Company (Brooklyn Union) serves the Brooklyn and Richmond Boroughs of New York City. Brooklyn Union faces high cost sources of supply from 3 interstate pipelines-- Transcontinental, Texas Eastern, and Tennessee--but has demonstrated considerable dexterity in purchasing off peak and interruptable gas, lowering supply costs considerably. Residential sector sales accounted for 74 percent of Brooklyn Union's total sales in 1986. The capture rate on new residential units is 95 percent but continued conservation is likely to offset this growth to some extent. With the growth of the New York City service industry, the outlook for commercial sector sales is optimistic. Industrial sales are expected to remain generally flat. Brooklyn Union is also a member of the Boundary Gas consortium formed to purchase Canadian imports.

The New Jersey Natural Gas Company (New Jersey Natural) purchases nearly all of its gas supplies from Trans Eastern, but supply is constrained by pipeline capacity, leaving room for potential growth. It's end use sales portfolio resembles that of other Midddle Atlantic distributors in that sales to the residential sector accounted for 50 percent of total sales in 1986, with electric utility sales second at 24 percent. Growth is expected in both the residential and commerical sectors.

Footnotes

[1] The data on LDC deliveries by end-use classifications and purchases by supplier is obtained from Atlantic Information Services Inc. Natural Gas Marketing, 1988 Industry Directory (Washington D.C.: 1988). An additional source of information was L. A. Coad and K. R. Teitge, The United States Natural Gas Market Analysis Project, Canadian Energy Research Institute (Calgary: November 1985) p. 95-212.

APPENDIX G

THE GENERALIZED EQUILIBRIUM MODELLING METHODOLOGY (GEMS)

Appendix G

THE GENERALIZED EQUILIBRIUM MODELLING METHODOLOGY (GEMS)

The Generalized Equilibrium Modelling System (GEMS) is a flexible network modelling methodology that has in the past been used to create a number of decision oriented economic models. The models are being used by a diverse cross section of firms and organizations to make informed investment and planning decisions. A GEMS analysis provides the analytical capability to model specific industry interactions and to quantify their major effects on the key industry players. The versatility and scope of the GEMS methodology has made it a powerful tool for addressing the complex issues and forces that interact to influence the future evolution of industry markets.

The underlying foundation of the GEMS methodology is decomposition. Large models are composed of a number of smaller sub-models linked together in a hierarchical network. Each sub-model represents the behavior of an agent, or group of agents, in the inter-active network. The behavior of the overall economy is based on the combination of actions undertaken by the individual agents. The power of this approach is in the fact that the economy is not represented as attempting to solve a single overall objective function, but rather, is represented by the sum of the actions of individual agents each attempting to solve their own specific behavioral options.

The structure of a GEMS model is based on a hierarchical level of activities that represent the complete array of technological and economic functions within an industry. The activities, such as resource production and end-use demand, are represented by generic models from the GEMS software library. These generic models are essentially the unit building blocks for the GEMS network.

The GEMS package consists of a large number of generic process models designed to effectively represent a number of industries. A list of some of the major process models and their application is shown in Table G.1. Each process model is essentially a set of mathematical equations that represents behavioral, financial, and technological interactions given a specific set of input parameters. The input

TABLE G.1
GENERIC PROCESS MODELS

Process Type	Represents	Example
○ Allocation	A market for a good or service	R/C/ Space Heat Market
□ Conversion	Transformation of several inputs into a single output	Coal Gasification
⬡ Resource	Production of a depletable resource	Offshore Gulf Gas Production
△ Transportation	Transportation of a product	El Paso Gas Pipeline
□ Electric Power	Generation of electric power	Coal Boiler
▭ Load Duration	Generates a load duration curve	—
▢ End-Use Demand	Generates demand for energy end uses	R/C Space Heat Demand

SOURCE: Decision Focus Inc. (DFI), Various Documents (Palo Alto, California: DFI, 1985 and 1986).

parameters represent process-specific attributes such as operating factors (capital, operating and maintenance costs, thermal efficiency), financial factors (return on equity, return on debt), and external factors (interest rates, labor costs). Further distinctions can be made by specifying optional attributes such as forecasting perfection, regulatory constraints and technical progress assumptions.

The generic models contained in the GEMS logic library represent an extensive and highly developed inventory of modelling capital available to the model user. Although each model is used to represent a large generic class of activities, there is a good deal of flexibility inherent to represent individual or more specific behavior. A wide slate of process parameters, in addition to the more generic structural features, allows the detailed individual representation.

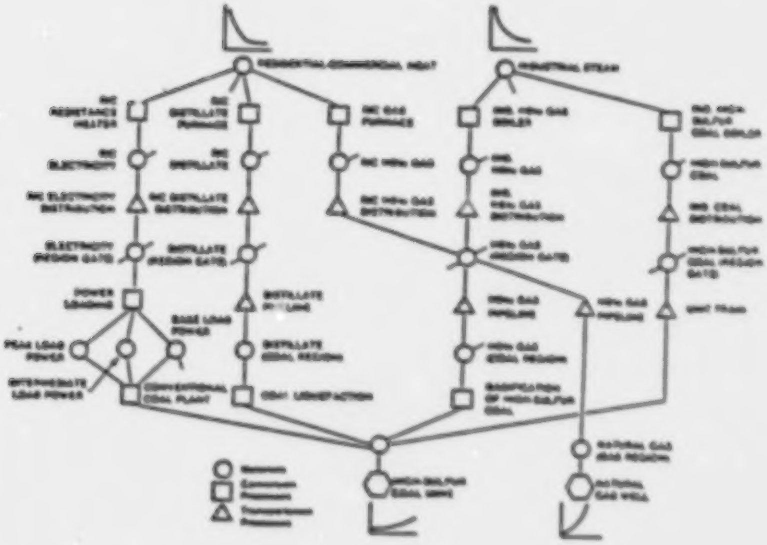
These generic processes are used to model the various activities within the industry. The scope of representation by each activity can be as small as a single process, such as production of a specific resource from a single technology for a specific geographic region, or as diverse as production from an entire continental industry, regardless of technology or regional distinction.

The complete set of industry activities are structured in a network diagram similar to that shown in Figure G.1. Each activity is represented in a network diagram by a particular geometric shape. A key showing which generic process is represented by each particular shape is shown at the bottom of the figure. The activities are joined by network links that represent the flow of commodities and payments through the network. Commodities flow upward through the processes, while commodity payments flow in the opposite direction.

A GEMS network is generally structured so that commodities flow from bottom to top. That is, resource extraction is represented at the bottom of the network; transportation, conversion and allocation processes are represented at intermediate nodes; and final consumption activities are portrayed at the top. A GEMS network can then be defined as all potential paths that a resource may follow through the network, from initial extraction at the bottom to end-use demand at the top. These are the chains of technologies that we refer to in Chapter 6.

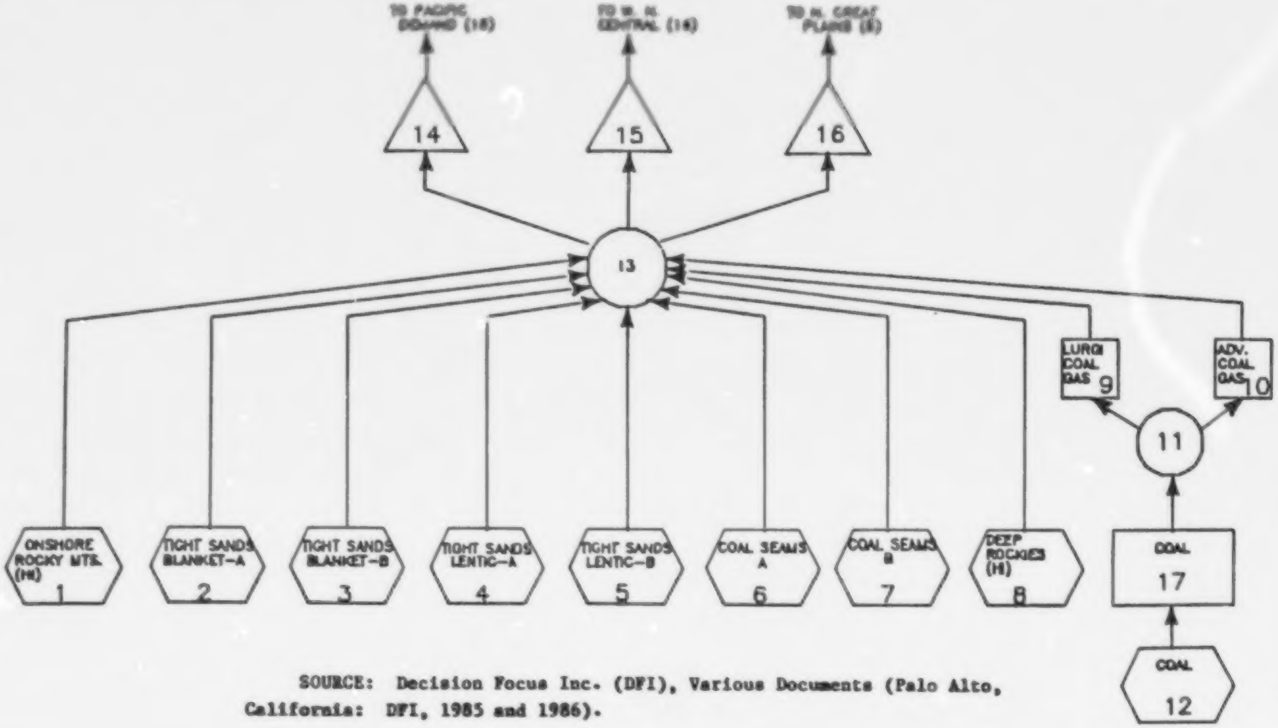
The diagrams in Figures G.2 and G.3 are specific examples of the general network structure used to describe the supply and demand

Figure G.1
A Typical Gems Network


RESIDENTIAL/COMMERCIAL HEAT
INDUSTRIAL STEAM
R/C RESISTANCE HEATER
R/C DISTILLATE FURNACE
R/C GAS FURNACE
IND. HIGH GAS BOILER
IND. HIGH SULFUR COAL BOILER
R/C ELECTRICITY
R/C DISTILLATE
R/C HIGH GAS
IND. HIGH GAS
HIGH SULFUR COAL
R/C ELECTRICITY DISTRIBUTION
R/C DISTILLATE DISTRIBUTION
R/C HIGH GAS DISTRIBUTION
IND. HIGH GAS DISTRIBUTION
IND. COAL DISTRIBUTION
ELECTRICITY (REGION GATE)
DISTILLATE (REGION GATE)
HIGH GAS (REGION GATE)
HIGH SULFUR COAL (REGION GATE)
POWER LOADING
DISTILLATE PIPELINE
HIGH GAS PIPELINE
HIGH GAS PIPELINE
UNIT TRAIN
BASE LOAD POWER
PEAK LOAD POWER
DISTILLATE (COAL REGION)
HIGH GAS (COAL REGION)
INTERMEDIATE LOAD POWER
CONVENTIONAL COAL PLANT
COAL LIQUEFACTION
GASIFICATION OF HIGH SULFUR COAL
NATURAL GAS (GAS REGION)
HIGH SULFUR COAL MINE
NATURAL GAS WELL
Conversion Process
Transportation Process

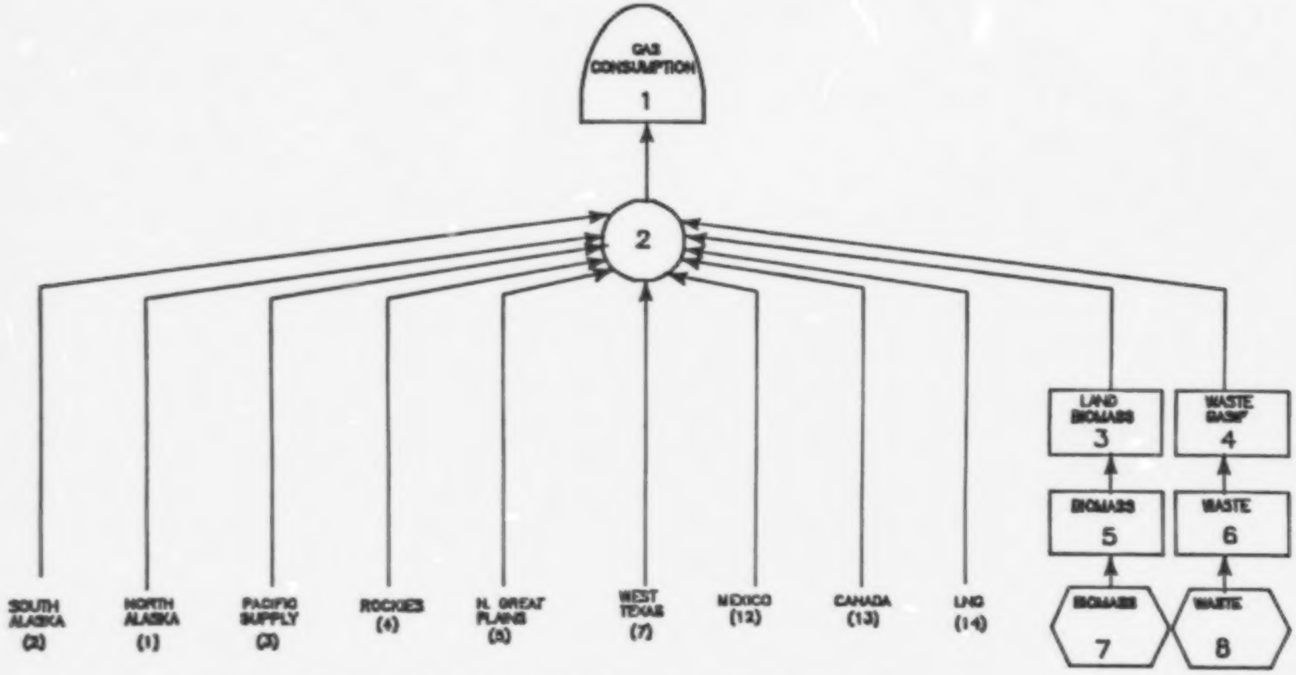
SOURCE: Decision Focus Inc. (DFI), Various Documents (Palo Alto, California: DFI, 1985 and 1986).

Figure G.2
Network Structure of the Rocky Mountain Supply Region


TO PACIFIC DEMAND (18)
TO W. N. CENTRAL (14)
TO N. GREAT PLAINS (8)
14
15
16
13
LURGI COAL GAS 9
ADV. COAL GAS 10
11
ONSHORE ROCKY MTS. (H) 1
TIGHT SANDS BLANKET-A 2
TIGHT SANDS BLANKET-B 3
TIGHT SANDS LENTIC-A 4
TIGHT SANDS LENTIC-B 5
COAL SEAMS A 6
COAL SEAMS B 7
DEEP ROCKIES (H) 8
COAL 17
COAL 12

SOURCE: Decision Focus Inc. (DFI), Various Documents (Palo Alto, California: DFI, 1985 and 1986).

Figure G.3
Network Structure of the Pacific Demand Region


GAS CONSUMPTION
1
2
SOUTH ALASKA (2)
NORTH ALASKA (1)
PACIFIC SUPPLY (3)
ROCKIES (4)
N. GREAT PLAINS (5)
WEST TEXAS (7)
MEXICO (12)
CANADA (13)
LNG (14)
LAND BIOMASS
3
WASTE GASIF
4
BIOMASS
5
WASTE
6
BIOMASS
7
WASTE
8

SOURCE: Decision Focus Inc. (DFI), Various Documents (Palo Alto, California: DFI, 1985 and 1986).

for gas on a regional basis in the gas model. Production from the Rocky Mountain supply sector is illustrated in Figure G.2. The geologic areas of the Rocky Mountain region include the overthrust region; the Four Corners coal region; the tight lenticular and blanket formation in Utah, Wyoming, and Colorado; the Green River Basin; and the Denver Basin. Within these formations, eight sources of conventional and unconventional gas are represented. In addition, two coal gasification sources are identified; Lurgi process with methanization and an advanced second generation process with methanization. The eight conventional and unconventional gas sources include:

- Conventional natural gas
- Deep natural gas (Parts A & B)
- Methane from tight blanket formation (Parts A & B)
- Methane from tight lenticular formation (Parts A & B)
- Methane from coal deposits (Parts A & B)

Gas from this region is assumed to have access to three different markets; the Pacific, West North Central, and Northern Great Plains regions.

The network depicting the process stucture within a demand sector is shown in Figure G.3 for the Pacific region. The network structure within each demand sector follows the same general form. There are several gas sources competing to supply the regional distribution companies. This competition is represented by the allocation process (the circle) in the network. The amount of gas required and the price elasticity of demand is represented by the characteristics of the regional demand function, the tombstone shaped figure at the top of the network.

The solution of the GEMS model is accomplished through an iterative process algorithm named the up/down algorithm. The solution method is one of successive approximations. That is, on each iteration the model converges closer to an equilibrium solution. This solution is essentially the answer to a set of non-linear equations, where the set of equations to be solved is encompassed in the potential paths of the network diagram.

The GEMS up/down algorithm derives its name from the manner in which it iterates in the network. Initially, the algorithm sets up a visitation sequence, the order in which the algorithm executes or "visits" each process in the network. Beginning at the network bottom, the algorithm starts the up/down sequence. A recent DFI report outlined the computational procedure within this network as the following six step process (Haas et al, 1986).

Step 1 Estimate the quantities output from every supply sector in the network.

Step 2 Pull the corresponding prices off of the supply curves associated with each sector.

Step 3 Work upward through all potential paths in the network, making:

(i) Required revenue calculations for all transportation and conversion processesss; and

(ii) Average price calculations for the allocation processes.

Step 4 Given required revenues delivered to demand processes, pull the demand quantities off of the demand curves.

Step 5 Work downward through all potential paths, making:

(i) Thermal efficiency calculations for all transportation and conversion processes; and

(ii) Market share calculations for all allocation processes.

Step 6 Check the resultant quantities brought back to the primary resource processes with those initially estimated in Step 1. If the difference between the original (up) quantity estimate for even one sector is above the specified tolerence level, the newly computed quantities from Step 5 are used and the process is repeated from Step 2 on.

It is this iterative process that is used to balance the supply and demand forces over the time horizon of the model. The solution is not complete until all relationships are simultaneously and exactly in equilibrium. The prices obtained clear all markets and there is no incentive for either producers or consumers to change their position.

To define and illustrate the conceptual methodology behind GEMS, a short example has been prepared. This example shows in simple terms what is required to determine, and what is meant by, the equilibrium prices and quantities in a basic supply/demand network.

Suppose we have the simple six process network as shown in Figure G.4. There are two gas sources, supply 1 and supply 2,

Figure G.4
A Simple Gems Network

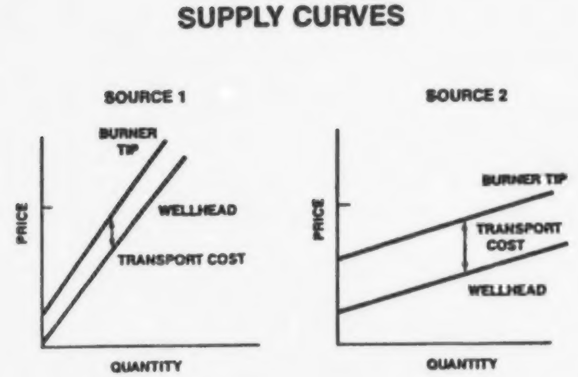
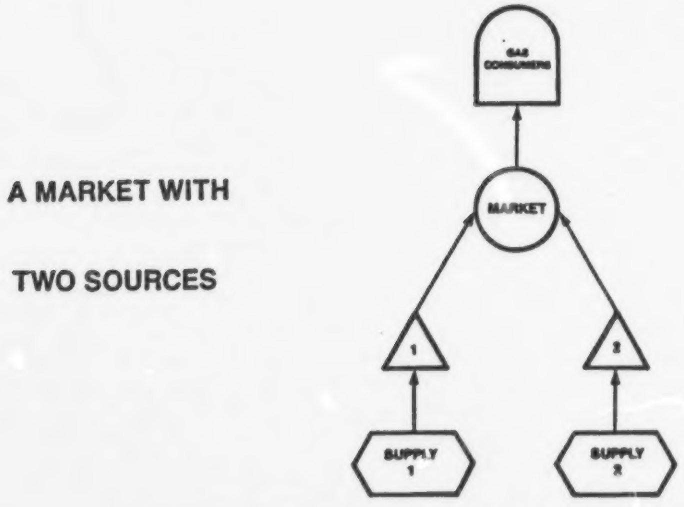


Figure G.5
Regional Supply Curves


A MARKET WITH
TWO SOURCES
GAS CONSUMERS
MARKET
1
2
SUPPLY 1
SUPPLY 2

SOURCE: Decision Focus Inc. (DFI), Various Documents (Palo Alto, California: DFI, 1985 and 1986).

represented by the hexagons at the bottom. These two sources flow through transportation networks, represented by the triangles, to compete for the gas consumption market at the top of the network. Each of the supply sources has its own supply curve with unique cost characteristics. As illustrated in Figure G.5, the burner-tip cost for each source is made up of the components of wellhead price and transportation cost.

At the market equilibrium point, the intersection of the regional demand curve and the combined supply curve (the numeric sum of the gross supply curves from each of the two competing sources) will dictate the equilibrium prices and quantities. This relationship is displayed in Figure G.6.

The prices received and the quantities provided by individual producers will not only be dictated by the equilibrium market conditions, but also by the characteristics of each individual supplier. As evidenced in Figure G.7, the prices received and the quantities allocated to each individual producer are a function of the individual supply elasticity and the regional transportation costs.

This simple example illustrates the relative ease of solution and intuitively obvious principles of market equilibrium in a static, single-market economy. A more complex and realistic situation is portrayed in Figure G.8. There are now two markets, each with its own individual demand function, for the two producing regions to supply. Different transportation charges between regions are again represented by the triangles.

Determining the static equilibrium prices and quantities is now a much more difficult task. In the previous example, the equilibrium relationships were determined solely by competition between the two supply regions. Now, the effects of the two individual demand regions must also be considered. Not only must consumers decide from where to buy their gas (based on the individual supplier resource curves), but the suppliers must also decide on where to sell their gas (based on the individual regional demand curves). The behavioral characteristics of each individual decision maker in the network must be considered.

The solution to this problem is not intuitively obvious. What is required is an iterative solution to a set of non-linear equations. The set of equations to be solved is conceptually encompassed by the network diagram. Optimal behavior by the individual agents (i.e.,

Figure G.6
Combined Supply/Demand Equilibrium

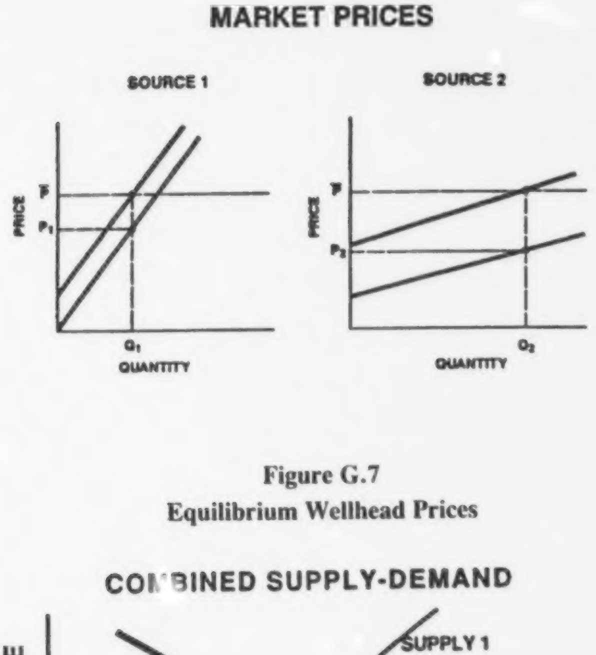
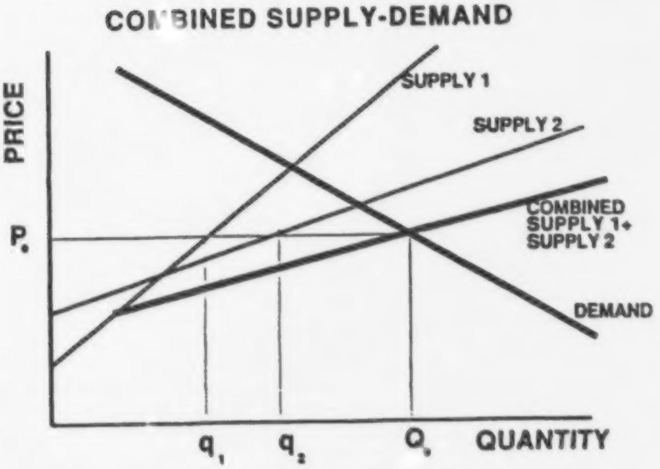
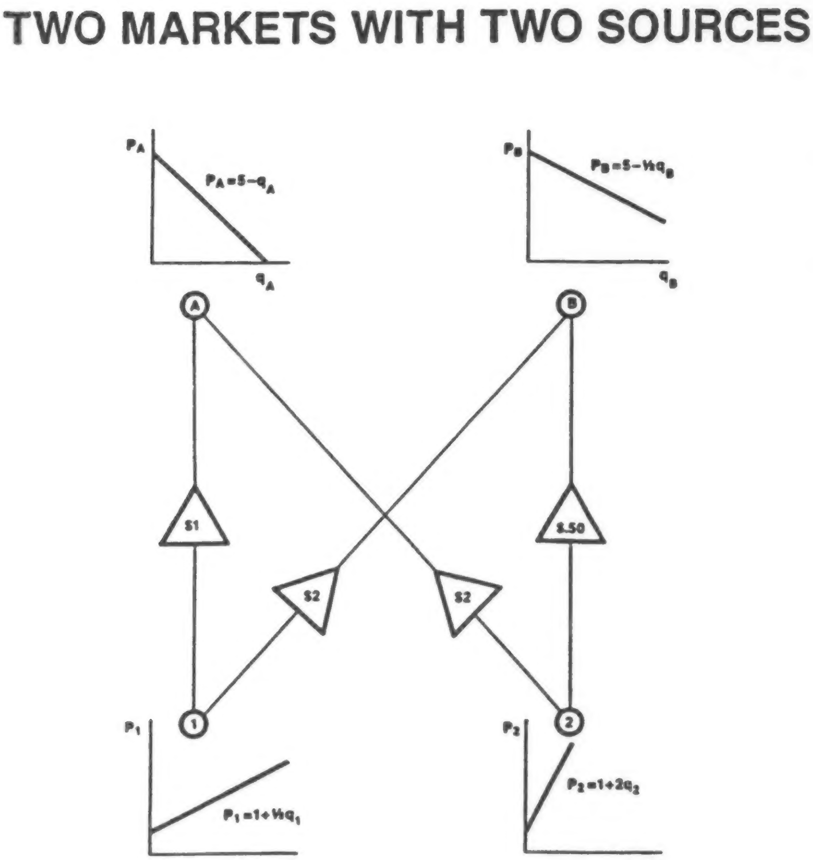


Figure G.7
Equilibrium Wellhead Prices



SOURCE: Decision Focus Inc. (DFI), Various Documents (Palo Alto, California: DFI, 1985 and 1986).

Figure G.8
A More Complex Gems Network


TWO MARKETS WITH TWO SOURCES
P_A
P_A=5−q_A
q_A
P_B
P_B=5−½q_B
q_B
A
B
$1
$.50
$2
$2
P_1
1
P_2
2
P_1=1+½q_1
q_1
P_2=1+2q_2
q_2

SOURCE: Decision Focus Inc. (DFI), Various Documents (Palo Alto, California: DFI, 1985 and 1986).

producers and consumers) is dependent on the action undertaken by other individuals. The multiplicity of demand and production regions necessitates the iterative approach. For an in depth description of the solution algorithm see Nesbitt (1984).

The end result of the iterative process is the equilibrium conditions for the four individual sectors as shown in Figure G.9. Again, it can be seen that neither the wellhead nor burner-tip prices are the same between regions at equilibrium. The quantities demanded from each supply region by each demand region depend on all other price and quantity relationships in the model.

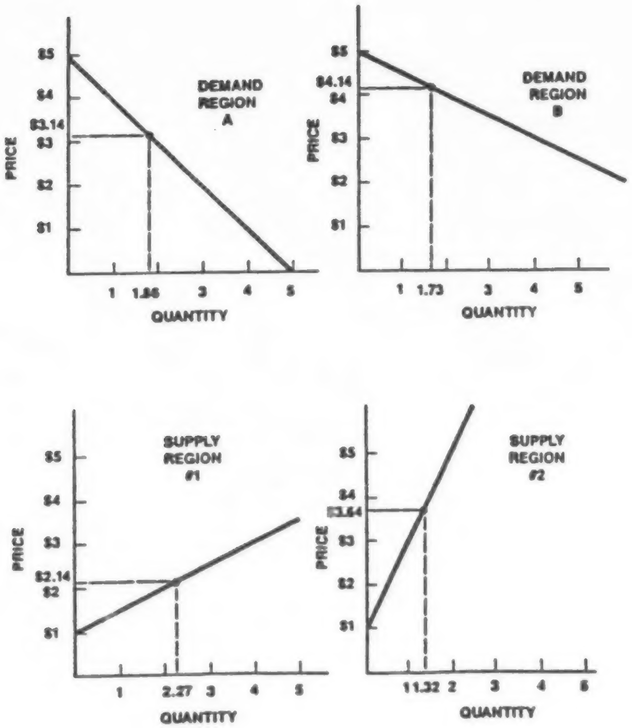
While this example illustrates the difficulty in determining market equilibrium prices and quantities, there are a number of complications that further increase the solution difficulty. These include the dynamic effects of time on production and consumption decisions, regulatory and tax effects, and financial, technological, and external variables, for individual market agents. GEMS accounts for each of these complications and determines their net effects on equilibrium market conditions.

The specific output of a GEMS solution is the equilibrium quantity and price tracks for every process in the network over the time horizon of the model. Also, the values of capacity additions for the depletable resource, transportation and conversion processes are determined. The output data can be aggregated and structured to alternative formats, providing further flexibility to reporting capabilities. For example, in the present gas model, production volumes can be represented over time by geographic region, by production technology and by geologic source. The volume and price paths can be combined to determine industry revenues and costs.

The flexible structure of the GEMS methodology makes it a valuable tool for performing scenario analysis on a number of resource-based industries. The underlying economic principles on which the logic is based makes it particularly suited to addressing long-term effects. Short-term constraints and fluctuations often mask the fundamental market principles that ultimately prevail.

Since GEMS is highly modular, it can be easily adapted to address a broad range of issues. It is important to note that the model is based on how the industry might evolve in the next five to fifty years, and not on an extrapolation of past events. Thus, it is

Figure G.9
Network Equilibrium Quantities and Price



SOURCE: Decision Focus Inc. (DFI), Various Documents (Palo Alto, California: DFI, 1985 and 1986).

particularly suited to addressing "what if" questions, providing valuable insight to strategic planning and management decisions.

The primary advantage of the GEMS methodology lies in its realistic modelling of basic industry forces through accepted economic principles. The model simulates industry interactions through the representation of the behavioral characteristics of individual agents. The hierarchical network structure provides the flexibility to represent specific behavioral, technological, and economic distinctions between agents, or groups of agents, in the economy. Continual development and application of GEMS models has provided substantial credibility for this approach.

Footnotes

[1] The major sources of this information is S. M. Haas, D. M. Nesbitt, and Jagjot Singh, The GRI North American Regional Natural Gas Supply-Demand Model, prepared for the Gas Research Institute (Chicago: GRI), May 1987.

APPENDIX H

DETAILED MODEL RESULTS

1. REFERENCE CASE RESULTS

Table H1.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports
1985	2.807	1.800	0.900
1990	3.786	2.140	1.424
1995	3.830	2.410	1.279
2000	4.132	2.640	1.330
2005	4.630	2.930	1.523
2010	4.983	3.250	1.447
2015	5.409	3.470	1.672
2020	5.326	3.690	1.344
2025	4.990	3.940	0.950
2030	4.655	4.100	0.556

Table H1.2: Summary Results for the U.S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.360	16.177	0.900	0.000	0.000
1990	15.714	16.133	1.424	0.034	0.010
1995	15.990	16.386	1.279	0.050	0.101
2000	16.600	17.183	1.330	0.070	0.152
2005	16.050	17.075	1.523	0.100	0.402
2010	15.830	17.019	1.447	0.123	0.601
2015	14.953	16.934	1.672	0.225	0.602
2020	15.790	16.844	1.344	0.136	0.601
2025	15.600	16.750	0.950	0.086	0.418
2030	17.500	16.664	0.556	0.037	0.234

Table H1.3: Western Canadian Sectoral Demand Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.260	0.190	0.500	0.950
1990	0.290	0.240	0.560	1.090
1995	0.310	0.280	0.600	1.190
2000	0.330	0.310	0.640	1.280
2005	0.360	0.340	0.690	1.390
2010	0.360	0.400	0.750	1.510
2015	0.380	0.430	0.780	1.590
2020	0.390	0.460	0.820	1.670
2025	0.410	0.500	0.850	1.760
2030	0.420	0.530	0.880	1.830

Table H1.4: Western Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	5.10	4.38	3.70	4.24
1995	5.92	5.20	4.54	5.10
2000	6.52	5.80	5.15	5.71
2005	7.14	6.42	5.78	6.34
2010	7.81	7.09	6.47	7.04
2015	8.65	7.93	7.32	7.89
2020	9.91	9.19	8.61	9.18
2025	10.80	10.08	9.52	10.10
2030	12.46	11.74	11.22	11.80

Table H1.5: Ontario and Eastern Canadian Sectoral Demand Quantities (quadrillion BTU's)

		ONTARIO			EASTERN CANADA
Year	Residential	Commercial	Industrial	Total	Total
1985	0.190	0.180	0.300	0.670	0.180
1990	0.220	0.240	0.340	0.800	0.250
1995	0.240	0.270	0.400	0.910	0.310
2000	0.250	0.310	0.440	1.000	0.360
2005	0.260	0.360	0.490	1.110	0.430
2010	0.280	0.420	0.540	1.240	0.500
2015	0.290	0.460	0.570	1.320	0.560
2020	0.300	0.500	0.610	1.410	0.610
2025	0.310	0.540	0.650	1.500	0.680
2030	0.320	0.590	0.690	1.600	0.750

Table H1.6: Ontario and Eastern Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

		ONTARIO			EASTERN CANADA
Year	Residential	Commercial	Industrial	Average Price	Average Price
1990	6.20	5.18	4.61	5.26	5.12
1995	7.08	6.06	5.51	6.14	6.03
2000	7.71	6.69	6.15	6.78	6.66
2005	8.35	7.33	6.80	7.43	7.30
2010	9.05	8.03	7.51	8.15	8.01
2015	9.90	8.86	8.37	9.01	8.87
2020	11.16	10.14	9.65	10.29	10.18
2025	12.09	11.07	10.60	11.23	11.14
2030	13.60	12.58	12.13	12.76	12.80

Table H1.7: Canadian Exports by U.S Demand Region Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1985	0.510	0.000	0.390	0.000	0.900
1990	0.566	0.155	0.428	0.274	1.423
1995	0.465	0.185	0.347	0.282	1.279
2000	0.409	0.201	0.364	0.355	1.329
2005	0.376	0.217	0.443	0.484	1.520
2010	0.309	0.208	0.267	0.660	1.444
2015	0.234	0.161	0.315	0.960	1.670
2020	0.144	0.098	0.214	0.886	1.342
2025	0.097	0.066	0.163	0.624	0.950
2030	0.050	0.033	0.111	0.361	0.555

Table H1.8: Canadian Exports by U.S Demand Region Delivered Prices ($1985 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	3.92	3.97	4.65	4.94	4.34
1995	4.74	4.71	5.54	5.84	5.20
2000	5.33	5.30	6.15	6.47	5.85
2005	5.92	5.88	6.77	7.11	6.54
2010	6.57	6.53	7.46	7.82	7.30
2015	7.41	7.37	8.29	8.57	8.24
2020	8.69	8.67	9.52	9.75	9.52
2025	9.54	9.51	10.41	10.60	10.38
2030	11.32	11.30	11.99	12.27	12.08

Table H1.9: Competing Gas Sources in the Pacific Region Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.000	0.494	0.737	0.332	0.566	2.133
1995	0.020	0.621	1.017	0.235	0.465	2.359
2000	0.032	0.633	1.266	0.165	0.409	2.506
2005	0.041	0.630	1.362	0.111	0.376	2.524
2010	0.039	0.608	1.319	0.070	0.309	2.366
2015	0.044	0.571	1.408	0.046	0.234	2.320
2020	0.028	0.511	1.547	0.033	0.144	2.280
2025	0.019	0.398	1.662	0.037	0.097	2.240
2030	0.010	0.285	1.778	0.041	0.050	2.200

Table H1.10: Competing Gas Sources in the Pacific Region Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.74	3.88	3.78	4.41	3.92	3.93
1995	5.10	4.50	4.38	5.12	4.74	4.56
2000	5.79	5.16	4.94	5.82	5.33	5.13
2005	6.42	5.75	5.52	6.58	5.92	5.69
2010	7.14	6.30	6.08	7.37	6.57	6.20
2015	7.71	6.95	6.62	8.23	7.41	6.78
2020	9.33	7.55	7.08	8.80	8.69	7.29
2025	10.42	7.86	7.22	8.71	9.54	7.40
2030	11.94	8.45	7.39	8.69	11.32	7.54

Table H1.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	0.968	0.000	0.464	0.098	0.155	1.686
1995	1.089	0.000	0.293	0.086	0.185	1.654
2000	1.122	0.000	0.185	0.071	0.201	1.579
2005	1.094	0.000	0.118	0.056	0.217	1.485
2010	1.099	0.000	0.079	0.043	0.208	1.429
2015	1.151	0.000	0.051	0.031	0.161	1.395
2020	1.183	0.022	0.033	0.025	0.098	1.360
2025	0.974	0.241	0.023	0.023	0.066	1.325
2030	0.765	0.459	0.012	0.021	0.033	1.290

Table H1.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.79	0.00	4.30	4.27	3.97	3.97
1995	4.38	0.00	5.00	4.96	4.71	4.55
2000	4.93	0.00	5.68	5.64	5.30	5.10
2005	5.52	0.00	6.39	6.37	5.88	5.67
2010	6.07	0.00	7.12	7.13	6.53	6.23
2015	6.60	0.00	8.00	7.96	7.37	6.77
2020	7.07	8.06	8.76	8.52	8.67	7.27
2025	7.20	7.43	9.05	8.43	9.51	7.42
2030	7.37	7.13	9.59	8.41	11.38	7.42

Table H1.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.137
1990	0.000	0.000	1.465	1.470	0.084	0.428	3.078
1995	0.000	0.000	1.351	1.376	0.066	0.347	2.897
2000	0.000	0.000	1.276	1.273	0.054	0.364	2.792
2005	0.000	0.000	1.156	1.126	0.045	0.443	2.638
2010	1.107	0.000	0.691	0.672	0.027	0.267	2.546
2015	1.203	0.000	0.583	0.539	0.023	0.315	2.470
2020	1.221	0.397	0.439	0.387	0.023	0.214	2.390
2025	1.209	1.268	0.338	0.300	0.019	0.163	2.310
2030	1.198	2.140	0.237	0.212	0.015	0.111	2.230

Table H1.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Average Price
1990	0.00	0.00	4.45	4.45	5.17	4.65	4.41
1995	0.00	0.00	5.17	5.16	5.97	5.54	5.13
2000	0.00	0.00	5.86	5.86	6.80	6.15	5.80
2005	0.00	0.00	6.59	6.61	7.63	6.77	6.51
2010	5.89	0.00	7.34	7.41	8.57	7.46	6.79
2015	7.84	0.00	8.23	8.30	9.48	8.29	7.91
2020	8.33	8.40	9.01	9.45	9.98	9.52	8.49
2025	8.01	7.75	9.31	9.31	10.04	10.41	8.10
2030	7.97	7.45	9.85	9.56	9.86	11.99	7.93

Table H1.15: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.595	0.340	0.000	0.274	2.218
1995	1.685	0.220	0.000	0.282	2.279
2000	1.782	0.160	0.133	0.355	2.430
2005	1.532	121.000	0.340	0.484	2.477
2010	1.302	0.200	0.494	0.660	2.656
2015	1.064	0.186	0.486	0.960	2.696
2020	1.095	0.267	0.488	0.886	2.736
2025	1.075	0.738	0.340	0.624	2.776
2030	1.056	1.208	0.191	0.361	2.816

Table H1.16: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.77	5.59	0.00	4.94	4.90
1995	5.40	6.37	0.00	5.84	5.33
2000	6.09	7.11	6.71	6.47	6.25
2005	6.95	7.88	7.12	7.11	7.07
2010	7.84	8.18	7.90	7.82	7.87
2015	8.83	9.40	8.98	8.57	8.80
2020	9.60	10.03	9.95	9.75	9.75
2025	9.67	9.69	11.12	10.60	10.07
2030	9.79	9.42	12.51	12.27	10.13

Table H1.17: Domestic Production by Region
(quadrillion BTU's)

	Alberta						
Year	Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.807
1990	3.201	0.000	0.439	0.067	0.000	0.000	3.706
1995	2.957	0.097	0.667	0.116	0.000	0.000	3.838
2000	3.178	0.132	0.678	0.138	0.000	0.000	4.132
2005	3.596	0.160	0.733	0.132	0.000	0.000	4.638
2010	3.720	0.236	0.757	0.116	0.000	0.000	4.903
2015	3.420	0.281	0.689	0.094	0.334	0.591	5.409
2020	2.567	0.614	0.572	0.108	0.655	0.809	5.326
2025	2.104	0.992	0.504	0.104	0.673	0.613	4.990
2030	1.640	1.371	0.437	0.099	0.691	0.417	4.655

Table H1.18: Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

	Alberta						Average
Year	Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Price
1990	3.10	0.00	3.46	3.67	0.00	0.00	3.15
1995	3.97	4.35	4.17	4.45	0.00	0.00	4.03
2000	4.55	5.08	4.74	5.15	0.00	0.00	4.61
2005	5.15	5.77	5.31	5.94	0.00	0.00	5.20
2010	5.83	6.38	5.94	6.82	0.00	0.00	5.81
2015	6.67	7.22	6.76	7.86	5.58	6.76	6.67
2020	7.99	8.10	8.02	9.01	5.72	7.81	7.72
2025	8.81	9.09	8.83	10.03	5.72	8.60	8.45
2030	10.69	10.19	10.70	11.95	5.83	10.14	9.80

Table H1.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.358	0.519	0.653	0.666	0.662	0.639	0.601	0.538	0.419	0.380
Rocky Mountains	1.504	1.854	2.290	2.596	2.669	2.628	2.788	3.164	3.267	3.370
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.367	2.130	3.900
Anderko	2.829	2.460	2.293	2.300	2.273	1.947	1.871	1.589	1.150	0.712
West Texas	1.478	1.363	1.314	1.371	1.268	1.158	1.307	2.196	3.014	3.901
Gulf Coast	9.406	8.204	7.741	7.778	7.395	6.706	6.208	5.194	3.668	2.142
Midwest	0.123	0.119	0.114	0.107	0.101	0.084	0.086	0.146	0.288	0.429
Appalachian	0.431	0.961	1.349	1.630	1.450	1.229	0.992	1.083	1.165	1.247
Total Lower 48	16.128	15.482	15.755	16.447	15.817	14.364	13.385	14.191	15.101	16.000
South Alaska	0.232	0.232	0.232	0.232	0.233	0.233	0.233	0.218	0.182	0.145
North Alaska	0.000	0.000	0.000	0.000	0.000	1.234	1.336	1.373	1.402	1.432
Total U.S	16.360	15.714	15.987	16.679	16.049	15.831	14.954	15.782	16.672	17.578

Table H1.20: U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.860	9.445	9.376	9.334	8.490	7.285	6.310	5.236	3.811	2.386
Lower 48 Offshore	4.713	4.493	4.617	4.799	4.465	4.004	3.590	2.813	1.987	1.161
Lower 48 Deep	1.555	1.543	1.762	2.314	2.862	3.075	3.485	3.475	2.469	1.823
Alaskan	0.232	0.232	0.232	0.232	0.233	1.467	1.568	1.596	1.574	1.577
Lurgi Coal Gas	0.000	0.000	0.000	0.000	0.000	0.000	0.474	2.674	6.640	10.607
Total	16.360	15.714	15.987	16.679	16.049	15.831	14.954	15.782	16.672	17.578

Table H1.21: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.15	3.74	4.39	4.96	5.49	6.13	6.71	7.01	7.58
Rocky Mountains	2.86	3.41	3.94	4.49	5.01	5.53	5.99	6.09	6.20
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	0.00	7.29	6.41	6.12
Anderko	3.41	4.08	4.72	5.40	6.09	6.91	7.62	7.91	8.49
West Texas	3.45	4.11	4.76	5.49	6.26	7.05	7.24	7.07	7.04
Gulf Coast	3.49	4.16	4.83	5.54	6.31	7.15	7.95	8.15	8.67
Midwest	4.24	5.06	5.79	6.57	7.48	8.41	8.81	8.85	8.69
Appalachian	3.54	4.27	5.00	5.87	6.76	7.80	8.52	8.51	8.56
Average	3.40	4.03	4.67	5.35	6.06	7.03	7.40	7.23	7.09

2. POLICY CASE: 25SURP

Table H2.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports to U.S.
1985	2.807	1.800	0.900
1990	3.455	2.289	1.032
1995	3.305	2.400	0.774
2000	3.345	2.561	0.649
2005	3.655	2.814	0.689
2010	3.969	3.115	0.683
2015	4.622	3.357	1.053
2020	4.676	3.588	0.854
2025	4.529	3.863	0.613
2030	4.381	4.138	0.371

Table H2.2: Summary Results for the U.S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.361	16.177	0.900	0.056	0.000
1990	17.690	17.584	1.032	0.042	0.010
1995	16.941	16.792	0.774	0.079	0.102
2000	17.376	17.185	0.649	0.114	0.153
2005	16.704	16.903	0.689	0.167	0.405
2010	16.359	16.778	0.683	0.202	0.606
2015	15.712	16.685	1.053	0.356	0.606
2020	16.067	16.653	0.854	0.206	0.603
2025	16.932	16.653	0.613	0.131	0.421
2030	17.796	16.652	0.371	0.055	0.238

Table H2.3: Western Canadian Sectoral Demand
Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.260	0.190	0.500	0.950
1990	0.306	0.254	0.593	1.153
1995	0.316	0.286	0.573	1.175
2000	0.328	0.309	0.596	1.233
2005	0.353	0.333	0.642	1.328
2010	0.350	0.389	0.702	1.441
2015	0.370	0.418	0.747	1.535
2020	0.380	0.449	0.793	1.622
2025	0.397	0.485	0.835	1.717
2030	0.414	0.522	0.876	1.812

Table H2.4: Western Canadian Sectoral Demand
Burnertip Prices ($1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	5.46	4.74	4.07	4.59
1995	6.29	5.57	4.92	5.45
2000	7.09	6.37	5.73	6.25
2005	7.69	6.97	6.35	6.86
2010	8.38	7.66	7.05	7.54
2015	8.96	8.24	7.64	8.12
2020	10.27	9.55	8.98	9.44
2025	11.13	10.41	9.85	10.30
2030	12.38	11.66	11.13	11.57

Table H2.5: Ontario and Eastern Canadian Sectoral Demand
Quantities (quadrillion BTU's)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Total	Total
1985	0.190	0.180	0.300	0.670	0.180
1990	0.235	0.256	0.372	0.863	2.289
1995	0.247	0.278	0.387	0.912	2.400
2000	0.251	0.311	0.414	0.976	2.561
2005	0.257	0.355	0.460	1.072	2.814
2010	0.274	0.411	0.510	1.195	3.115
2015	0.283	0.450	0.548	1.281	3.357
2020	0.293	0.489	0.591	1.373	3.588
2025	0.305	0.535	0.639	1.479	3.863
2030	0.316	0.582	0.687	1.585	4.138

Table H2.6: Ontario and Eastern Canadian Sectoral Demand
Burnertip Prices ($1985 U.S per MMBTU)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Average Price	Average Price
1990	6.57	5.55	4.98	5.58	5.35
1995	7.46	6.44	5.89	6.48	6.23
2000	8.30	7.28	6.74	7.31	7.07
2005	8.91	7.89	7.37	7.91	7.67
2010	9.63	8.61	8.10	8.63	8.38
2015	10.23	9.21	8.71	9.22	8.97
2020	11.57	10.55	10.07	10.56	10.31
2025	12.38	11.36	10.90	11.37	11.12
2030	13.53	12.51	12.06	12.52	12.39

Table H2.7: Canadian Exports by U.S Demand Region
Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1985	0.510	0.000	0.390	0.000	0.900
1990	0.488	0.071	0.331	0.142	1.032
1995	0.340	0.077	0.217	0.139	0.773
2000	0.250	0.076	0.172	0.150	0.648
2005	0.198	0.081	0.186	0.223	0.688
2010	0.150	0.080	0.114	0.338	0.682
2015	0.128	0.077	0.187	0.659	1.051
2020	0.080	0.048	0.126	0.599	0.853
2025	0.054	0.032	0.096	0.430	0.612
2030	0.028	0.016	0.066	0.260	0.370

Table H2.8: Canadian Exports by U.S Demand Region
Delivered Prices ($1987 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	4.28	4.30	5.02	5.31	4.66
1995	5.10	5.08	5.90	6.22	5.52
2000	5.83	5.78	6.74	7.08	6.36
2005	6.43	6.39	7.34	7.68	7.08
2010	7.09	7.04	8.04	8.40	7.89
2015	7.65	7.60	8.63	8.95	8.64
2020	8.95	8.90	9.91	10.13	9.92
2025	9.89	9.86	10.62	10.76	10.61
2030	11.17	11.17	11.84	12.05	11.91

Table H2.9: Competing Gas Sources in the Pacific Region
Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.007	0.578	0.867	0.363	0.488	2.302
1995	0.039	0.667	1.105	0.247	0.340	2.400
2000	0.059	0.664	1.346	0.172	0.250	2.492
2005	0.076	0.671	1.422	0.118	0.198	2.488
2010	0.069	0.629	1.382	0.074	0.150	2.327
2015	0.074	0.576	1.441	0.049	0.128	2.286
2020	0.046	0.498	1.575	0.036	0.080	2.255
2025	0.031	0.380	1.691	0.040	0.054	2.226
2030	0.016	0.262	1.807	0.044	0.028	2.196

Table H2.10: Competing Gas Sources in the Pacific Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.74	4.01	3.91	4.52	4.28	4.11
1995	5.10	4.65	4.52	5.23	5.10	4.79
2000	5.79	5.32	5.09	5.95	5.83	5.35
2005	6.42	5.91	5.70	6.73	6.43	5.92
2010	7.14	6.48	6.23	7.55	7.09	6.45
2015	7.71	7.12	6.77	8.39	7.65	6.93
2020	9.33	7.69	7.17	8.85	8.95	7.45
2025	10.42	7.96	7.25	8.71	9.89	7.52
2030	11.94	8.52	7.38	8.66	11.17	7.49

Table H2.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	1.128	0.000	0.508	0.116	0.071	1.823
1995	1.200	0.000	0.309	0.102	0.077	1.688
2000	1.220	0.000	0.194	0.085	0.076	1.574
2005	1.190	0.000	0.126	0.069	0.081	1.466
2010	1.192	0.000	0.084	0.051	0.080	1.407
2015	1.207	0.001	0.055	0.037	0.077	1.376
2020	1.205	0.032	0.035	0.029	0.048	1.348
2025	0.982	0.257	0.024	0.026	0.032	1.320
2030	0.758	0.481	0.013	0.023	0.016	1.292

Table H2.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.91	0.00	4.42	4.38	4.30	4.10
1995	4.52	0.00	5.12	5.07	5.08	4.69
2000	5.08	0.00	5.82	5.77	5.78	5.25
2005	5.69	0.00	6.55	6.51	6.39	5.84
2010	6.22	0.00	7.31	7.31	7.04	6.37
2015	6.76	9.00	8.19	8.12	7.60	6.91
2020	7.16	8.05	8.90	8.57	8.90	7.32
2025	7.23	7.40	9.12	8.43	9.86	7.38
2030	7.36	7.11	9.60	8.39	11.17	7.35

Table H2.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.686
1990	0.000	0.000	1.662	1.695	0.095	0.331	3.783
1995	0.000	0.000	1.436	1.510	0.070	0.217	3.233
2000	0.000	0.000	1.345	1.410	0.057	0.172	2.984
2005	0.000	0.000	1.262	1.271	0.049	0.186	2.768
2010	1.128	0.000	0.771	0.775	0.050	0.114	2.818
2015	1.209	0.017	0.651	0.620	0.026	0.187	2.711
2020	1.222	0.487	0.460	0.423	0.024	0.126	2.742
2025	1.209	1.377	0.354	0.327	0.020	0.096	3.383
2030	1.196	2.267	0.247	0.231	0.016	0.066	4.024

Table H2.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Average Price
1990	0.00	0.00	4.57	4.57	5.31	5.20	4.64
1995	0.00	0.00	5.29	5.27	6.11	5.90	5.34
2000	0.00	0.00	6.01	5.99	6.97	6.74	6.06
2005	0.00	14.44	6.75	6.76	7.83	7.34	6.81
2010	6.09	11.06	7.53	7.58	8.78	8.04	7.06
2015	8.07	9.37	8.43	8.49	9.66	8.63	8.31
2020	8.39	8.39	9.15	9.28	10.04	9.91	8.74
2025	8.00	7.72	9.38	9.37	10.05	10.62	8.25
2030	7.95	7.42	9.86	9.55	9.00	11.04	7.93

Table H2.15: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.903	0.377	0.010	0.142	2.431
1995	1.872	0.236	0.092	0.139	2.339
2000	1.965	0.173	0.138	0.150	2.426
2005	1.719	0.142	0.357	0.223	2.441
2010	1.455	0.282	0.524	0.338	2.600
2015	1.206	0.256	0.515	0.659	2.636
2020	1.235	0.348	0.506	0.599	2.688
2025	1.162	0.810	0.353	0.430	2.754
2030	1.089	1.271	0.200	0.260	2.820

Table H2.16: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.92	5.75	5.96	5.31	5.08
1995	5.58	6.51	6.13	6.22	5.73
2000	6.30	7.28	6.96	7.08	6.46
2005	7.21	8.08	7.43	7.68	7.34
2010	8.16	8.40	8.24	8.40	8.23
2015	9.08	9.63	9.28	8.95	9.14
2020	9.70	10.11	10.12	10.13	9.93
2025	9.67	9.65	11.12	10.76	10.02
2030	9.74	9.35	12.51	12.05	9.97

Table H2.17: Domestic Production by Region
(quadrillion BTU's)

	Alberta						
Year	Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.81
1990	2.981	0.000	0.406	0.069	0.000	0.000	3.46
1995	2.707	0.043	0.473	0.083	0.000	0.000	3.31
2000	2.643	0.088	0.507	0.107	0.000	0.000	3.34
2005	2.918	0.087	0.508	0.114	0.000	0.028	3.66
2010	3.132	0.128	0.553	0.109	0.004	0.044	3.97
2015	3.451	0.133	0.610	0.090	0.039	0.299	4.62
2020	2.888	0.320	0.631	0.091	0.181	0.566	4.68
2025	2.498	0.474	0.576	0.095	0.416	0.472	4.53
2030	2.108	0.627	0.521	0.098	0.650	0.377	4.38

Table H2.18: Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

	Alberta						
Year	Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Average Price
1990	3.46	4.99	3.77	4.04	0.00	11.24	3.51
1995	4.32	4.89	4.53	4.99	8.94	8.22	4.37
2000	5.13	5.69	5.21	5.80	7.52	6.78	5.18
2005	5.70	6.55	5.80	6.52	6.82	6.16	5.76
2010	6.40	7.11	6.44	7.39	6.60	6.85	6.46
2015	6.96	7.91	6.98	8.20	6.83	7.19	7.03
2020	8.32	8.77	8.24	9.57	7.45	8.17	8.31
2025	9.11	9.66	9.18	10.40	7.94	8.74	9.06
2030	10.41	10.55	10.46	11.73	8.17	9.91	10.09

Table H2.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.358	0.608	0.702	0.698	0.706	0.662	0.606	0.523	0.400	0.276
Rocky Mountains	1.504	2.168	2.506	2.790	2.841	2.799	2.890	3.246	3.303	3.360
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.011	0.492	2.317	4.142
Andarko	2.829	2.753	2.408	2.368	2.386	2.004	1.884	1.541	1.099	0.657
West Texas	1.478	1.521	1.387	1.404	1.302	1.184	1.418	2.286	3.161	4.035
Gulf Coast	9.406	9.127	8.121	8.051	7.618	6.909	6.215	5.058	3.524	1.990
Midwest	0.123	0.134	0.119	0.110	0.104	0.087	0.092	0.165	0.321	0.477
Appalachian	0.431	1.137	1.463	1.723	1.516	1.223	1.018	1.161	1.223	1.284
Total Lower 48	16.129	17.448	16.706	17.144	16.473	14.868	14.134	14.472	15.347	16.221
South Alaska	0.232	0.241	0.235	0.233	0.233	0.233	0.234	0.219	0.182	0.144
North Alaska	0.000	0.000	0.000	0.000	0.000	1.259	1.343	1.375	1.404	1.433
Total U.S	17.317	18.774	17.896	18.292	17.965	17.850	17.727	17.730	18.095	18.460

Table H2.21: U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.860	10.604	9.938	9.705	8.812	7.426	6.266	5.051	3.627	2.203
Lower 48 Offshore	4.713	5.004	4.873	4.988	4.586	4.116	3.552	2.723	1.901	1.078
Lower 48 Deep	1.555	1.761	1.894	2.450	3.072	3.275	3.589	3.498	2.544	1.680
Alaskan	0.232	0.241	0.235	0.233	0.233	1.492	1.577	1.595	1.586	1.577
Lurgi Coal Gas	0.000	0.000	0.000	0.000	0.002	0.049	0.727	3.282	7.258	11.234
Total	17.317	18.774	17.896	18.292	17.965	17.850	17.727	17.730	18.095	18.460

Table H2.21: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.27	3.89	4.54	5.12	5.67	6.29	6.85	7.10	7.64
Rocky Mountains	2.98	3.54	4.08	4.66	5.16	5.69	6.07	6.11	6.19
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	9.51	7.22	6.40	6.11
Andarko	3.52	4.20	4.86	5.55	6.27	7.09	7.76	7.98	8.51
West Texas	3.55	4.21	4.89	5.62	6.42	7.16	7.26	7.07	7.03
Gulf Coast	3.60	4.27	4.95	5.69	6.46	7.34	8.06	8.20	8.69
Midwest	4.37	5.13	5.94	6.76	7.70	8.57	8.87	8.88	8.63
Appalachian	3.69	4.46	5.21	6.14	7.11	8.08	8.58	8.48	8.51
Average	3.51	4.15	4.81	5.51	6.21	6.97	7.43	7.24	7.06

3. POLICY CASE: 10SURP

Table H3.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports to U.S.
1985	2.807	1.600	0.900
1990	4.478	2.304	1.924
1995	4.608	2.544	1.888
2000	4.975	2.753	2.031
2005	5.427	3.029	2.186
2010	5.449	3.335	1.927
2015	5.771	3.518	1.948
2020	5.626	3.726	1.588
2025	5.244	3.961	1.121
2030	4.862	4.196	0.653

Table H3.2: Summary Results for the U.S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.361	16.177	0.900	0.056	0.000
1990	16.952	17.794	1.924	0.036	0.010
1995	16.118	17.119	1.888	0.045	0.101
2000	16.361	17.584	2.031	0.058	0.152
2005	15.644	17.334	2.186	0.081	0.385
2010	15.620	17.200	1.927	0.102	0.542
2015	15.334	17.000	1.948	0.190	0.581
2020	15.704	16.953	1.588	0.116	0.564
2025	16.555	16.817	1.121	0.074	0.391
2030	17.406	16.680	0.653	0.031	0.218

Table H3.3: Western Canadian Sectoral Demand
Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.260	0.190	0.500	0.950
1990	0.312	0.258	0.638	1.208
1995	0.327	0.296	0.632	1.255
2000	0.344	0.324	0.668	1.336
2005	0.373	0.352	0.715	1.440
2010	0.370	0.411	0.770	1.551
2015	0.388	0.438	0.787	1.613
2020	0.395	0.466	0.826	1.687
2025	0.409	0.500	0.854	1.763
2030	0.423	0.533	0.882	1.838

Table H3.4: Western Canadian Sectoral Demand
Burnertip Prices ($1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	4.98	4.26	3.58	4.09
1995	5.67	4.95	4.28	4.80
2000	6.25	5.53	4.88	5.39
2005	6.90	6.18	5.54	6.05
2010	7.62	6.90	6.28	6.76
2015	8.64	7.92	7.32	7.80
2020	9.81	9.09	8.50	8.97
2025	10.84	10.12	9.56	10.02
2030	12.39	11.67	11.14	11.58

Table H3.5: Ontario and Eastern Canadian Sectoral Demand
Quantities (quadrillion BTU's)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Total	Total
1985	0.190	0.180	0.300	0.670	0.180
1990	0.239	0.260	0.396	0.895	0.281
1995	0.254	0.286	0.420	0.960	0.330
2000	0.261	0.324	0.457	1.042	0.375
2005	0.269	0.373	0.505	1.147	0.443
2010	0.288	0.431	0.553	1.272	0.511
2015	0.295	0.469	0.575	1.339	0.567
2020	0.304	0.506	0.614	1.424	0.615
2025	0.313	0.550	0.653	1.515	0.684
2030	0.322	0.593	0.691	1.606	0.752

Table H3.6: Ontario and Eastern Canadian Sectoral Demand
Burnertip Prices ($1985 U.S per MMBTU)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Average Price	Average Price
1990	6.08	5.06	4.49	5.08	5.35
1995	6.82	5.80	5.24	5.83	6.23
2000	7.44	6.42	5.87	6.43	7.07
2005	8.11	7.09	6.56	7.10	7.67
2010	8.85	7.83	7.31	7.83	8.38
2015	9.87	8.85	8.35	8.86	8.97
2020	11.06	10.04	9.55	10.05	10.31
2025	12.12	11.10	10.63	11.11	11.12
2030	13.54	12.52	12.07	12.53	12.39

Table H3.7: Canadian Exports by U.S Demand Region
Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1985	0.510	0.000	0.390	0.000	0.900
1990	0.695	0.254	0.589	0.385	1.923
1995	0.610	0.311	0.538	0.427	1.886
2000	0.571	0.326	0.595	0.536	2.028
2005	0.524	0.321	0.675	0.663	2.183
2010	0.408	0.277	0.403	0.836	1.924
2015	0.284	0.191	0.396	1.074	1.945
2020	0.173	0.115	0.270	1.027	1.585
2025	0.116	0.077	0.203	0.722	1.119
2030	0.060	0.038	0.136	0.418	0.652

Table H3.8: Canadian Exports by U.S Demand Region
Delivered Prices ($1987 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	3.80	3.81	4.54	4.82	4.23
1995	4.49	4.47	5.27	5.57	4.95
2000	5.07	5.05	5.87	6.19	5.60
2005	5.69	5.66	6.53	6.86	6.30
2010	6.43	6.40	7.26	7.61	7.11
2015	7.48	7.47	8.26	8.46	8.18
2020	8.61	8.59	9.42	9.62	9.40
2025	9.65	9.64	10.44	10.64	10.43
2030	11.29	11.43	11.95	12.27	12.06

Table H3.9: Competing Gas Sources in the Pacific Region
Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.002	0.518	0.769	0.361	0.695	2.346
1995	0.015	0.612	0.995	0.240	0.610	2.472
2000	0.024	0.610	1.209	0.162	0.571	2.577
2005	0.030	0.599	1.310	0.107	0.524	2.574
2010	0.030	0.592	1.287	0.066	0.408	2.400
2015	0.035	0.573	1.394	0.043	0.284	2.343
2020	0.022	0.522	1.533	0.031	0.173	2.297
2025	0.015	0.412	1.648	0.035	0.116	2.251
2030	0.008	0.301	1.762	0.039	0.060	2.204

Table H3.10: Competing Gas Sources in the Pacific Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.74	3.82	3.72	4.40	3.80	3.87
1995	5.10	4.40	4.29	5.08	4.49	4.49
2000	5.79	5.05	4.84	5.76	5.07	5.04
2005	6.42	5.64	5.40	6.50	5.69	5.60
2010	7.14	6.19	5.98	7.28	6.43	6.18
2015	7.71	6.84	6.53	8.14	7.48	6.78
2020	9.33	7.45	7.02	8.76	8.61	7.34
2025	10.42	7.79	7.20	8.71	9.65	7.52
2030	11.94	8.41	7.39	8.71	11.29	7.56

Table H3.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	0.995	0.000	0.502	0.099	0.254	1.850
1995	1.043	0.000	0.298	0.077	0.311	1.729
2000	1.052	0.000	0.182	0.061	0.326	1.620
2005	1.031	0.000	0.113	0.047	0.321	1.513
2010	1.060	0.000	0.075	0.037	0.277	1.448
2015	1.140	0.000	0.049	0.027	0.191	1.407
2020	1.180	0.020	0.031	0.022	0.115	1.368
2025	0.976	0.234	0.022	0.021	0.077	1.330
2030	0.772	0.448	0.012	0.020	0.038	1.291

Table H3.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.73	0.00	4.28	4.26	3.81	3.92
1995	4.29	0.00	4.95	4.92	4.47	4.46
2000	4.84	0.00	5.60	5.58	5.05	5.00
2005	5.40	0.00	6.31	6.30	5.66	5.55
2010	5.97	0.00	7.03	7.05	6.40	6.14
2015	6.52	9.90	7.91	7.88	7.47	6.72
2020	7.00	8.06	8.69	8.47	8.59	7.21
2025	7.18	7.44	9.01	8.43	9.64	7.41
2030	7.30	7.15	8.57	8.43	11.43	7.39

Table H3.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.686
1990	0.000	0.000	1.581	1.559	0.091	0.589	3.820
1995	0.000	0.000	1.345	1.333	0.066	0.538	3.282
2000	0.000	0.000	1.215	1.171	0.051	0.595	3.033
2005	0.000	0.000	1.075	1.014	0.042	0.675	2.806
2010	1.103	0.000	0.637	0.600	0.025	0.403	2.768
2015	1.202	0.010	0.550	0.492	0.021	0.396	2.671
2020	1.221	0.383	0.416	0.356	0.021	0.270	2.668
2025	1.209	1.210	0.319	1.143	0.018	0.203	3.234
2030	1.197	2.037	0.221	1.930	0.014	0.136	3.799

Table H3.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Average Price
1990	0.00	0.00	4.43	4.45	5.15	4.54	4.47
1995	0.00	0.00	5.11	5.12	5.92	5.27	5.16
2000	0.00	0.00	5.78	5.81	6.73	5.87	5.82
2005	0.00	14.16	6.51	6.54	7.54	6.53	6.54
2010	5.89	10.86	7.24	7.34	8.46	7.26	6.74
2015	7.76	9.27	8.14	8.21	9.39	8.26	8.01
2020	8.30	8.40	8.94	9.07	9.93	9.42	8.64
2025	8.01	7.76	9.26	9.27	10.02	10.44	10.00
2030	7.97	7.46	9.84	9.56	9.90	11.95	12.40

Table H3.15: Competing Gas Sources in the Mid-Atlantic/New England Region Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.695	0.375	0.009	0.385	2.464
1995	1.646	0.230	0.088	0.427	2.391
2000	1.672	0.159	0.129	0.536	2.496
2005	1.428	0.117	0.316	0.663	2.524
2010	1.247	0.179	0.434	0.836	2.696
2015	1.031	0.167	0.458	1.074	2.729
2020	1.041	0.244	0.449	1.027	2.760
2025	1.038	0.716	0.312	0.722	2.788
2030	1.035	1.188	0.175	0.418	2.816

Table H3.16: Competing Gas Sources in the Mid-Atlantic/New England Region Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.73	5.56	5.66	4.82	4.87
1995	5.32	6.30	5.82	5.57	5.48
2000	5.99	7.01	6.57	6.19	6.13
2005	6.81	7.77	6.98	6.86	6.89
2010	7.68	8.10	7.84	7.61	7.71
2015	8.71	9.32	8.90	8.46	8.67
2020	9.54	9.99	9.89	9.62	9.67
2025	9.67	9.71	11.12	10.64	10.10
2030	9.82	9.45	12.51	12.27	10.19

Table H3.17: Domestic Production by Region
(quadrillion BTU's)

Year	Alberta Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.807
1990	3.732	0.002	0.651	0.092	0.000	0.000	4.477
1995	3.458	0.129	0.878	0.142	0.000	0.000	4.607
2000	3.741	0.181	0.891	0.158	0.000	0.003	4.974
2005	4.069	0.268	0.931	0.145	0.002	0.013	5.428
2010	3.897	0.379	0.836	0.123	0.199	0.066	5.500
2015	3.069	0.492	0.628	0.103	0.657	0.822	5.771
2020	2.278	0.950	0.545	0.134	0.681	1.039	5.627
2025	1.767	1.504	0.442	0.115	0.699	0.719	5.244
2030	1.256	2.057	0.338	0.096	0.716	0.398	4.861

Table H3.18: Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

Year	Alberta Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Average Price
1990	2.99	4.00	3.30	3.45	0.00	10.67	3.04
1995	3.71	4.03	3.94	4.15	6.81	7.67	3.78
2000	4.28	4.80	4.50	4.85	5.44	6.22	4.36
2005	4.93	5.40	5.09	5.69	4.77	5.70	5.00
2010	5.65	6.09	5.82	6.64	4.61	6.19	5.70
2015	6.69	6.92	6.86	7.74	4.61	6.64	6.50
2020	7.90	7.88	7.94	8.78	4.57	7.69	7.48
2025	8.97	8.80	8.96	10.27	4.52	8.65	8.31
2030	10.94	9.99	10.79	11.98	4.65	10.18	9.56

Table H3.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.358	0.545	0.643	0.641	0.630	0.622	0.603	0.549	0.433	0.316
Rocky Mountains	1.504	1.917	2.215	2.456	2.543	2.549	2.760	3.147	3.260	3.372
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.005	0.342	1.857	3.372
Andarko	2.829	2.673	2.325	2.266	2.212	1.922	1.878	1.607	1.174	0.741
West Texas	1.478	1.485	1.343	1.367	1.252	1.145	1.272	2.056	2.939	3.822
Gulf Coast	9.406	8.931	7.902	7.725	7.271	6.599	6.163	5.219	3.719	2.219
Midwest	0.123	0.132	0.117	0.106	0.099	0.083	0.085	0.137	0.269	0.400
Appalachian	0.431	1.028	1.338	1.566	1.403	1.240	1.008	1.058	1.142	1.226
Total Lower 48	16.129	16.711	15.883	16.127	15.410	14.160	13.774	14.115	14.792	15.468
South Alaska	0.232	0.241	0.235	0.233	0.233	0.233	0.232	0.217	0.181	0.145
North Alaska	0.000	0.000	0.000	0.000	0.000	1.226	1.333	1.372	1.402	1.431
Total U.S	17.317	18.922	18.152	18.602	18.296	18.191	18.058	17.972	18.140	18.308

Table H3.20: U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.860	10.117	9.387	9.120	8.279	7.235	6.374	5.340	3.914	2.488
Lower 48 Offshore	4.713	4.917	4.713	4.753	4.381	3.934	3.572	2.838	2.023	1.208
Lower 48 Deep	1.555	1.677	1.783	2.255	2.750	2.970	3.422	3.280	2.590	1.899
Alaskan	0.232	0.241	0.235	0.233	0.233	1.459	1.565	1.588	1.582	1.576
Lurgi Coal Gas	0.000	0.000	0.000	0.000	0.001	0.021	0.404	2.450	6.330	10.210
Total	17.317	18.922	18.152	18.602	18.296	18.191	18.058	17.972	18.140	18.308

Table H3.21: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.09	3.65	4.29	4.86	5.39	6.02	6.62	6.95	7.54
Rocky Mountains	2.81	3.33	3.85	4.37	4.92	5.45	5.93	6.07	6.21
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	10.16	7.33	6.42	6.12
Andarko	3.39	4.03	4.65	5.33	6.00	6.82	7.56	7.86	8.47
West Texas	3.44	4.07	4.71	5.43	6.19	6.99	7.23	7.07	7.04
Gulf Coast	3.48	4.12	4.78	5.47	6.23	7.07	7.88	8.11	8.65
Midwest	4.22	4.95	5.71	6.49	7.38	8.33	8.76	8.82	8.71
Appalachian	3.47	4.18	4.89	5.73	6.59	7.67	8.48	8.52	8.60
Average	3.38	3.98	4.61	5.27	5.96	6.71	7.31	7.23	7.14

4. POLICY CASE: BTAX

Table H4.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports to U.S.
1985	2.007	1.000	0.900
1990	3.588	2.404	1.045
1995	3.516	2.516	0.815
2000	3.708	2.765	0.794
2005	4.166	3.053	0.941
2010	4.544	3.379	0.969
2015	5.258	3.623	1.378
2020	5.307	3.863	1.151
2025	5.069	4.096	0.813
2030	4.830	4.328	0.475

Table H4.2: Summary Results for the U.S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.361	16.177	0.900	0.056	0.000
1990	17.689	17.595	1.045	0.040	0.010
1995	16.939	16.821	0.815	0.067	0.102
2000	17.293	17.236	0.794	0.093	0.153
2005	16.531	16.966	0.941	0.133	0.404
2010	16.163	16.850	0.969	0.161	0.604
2015	15.505	16.761	1.378	0.288	0.604
2020	15.838	16.712	1.151	0.170	0.602
2025	16.681	16.679	0.813	0.108	0.419
2030	17.523	16.646	0.475	0.046	0.236

Table H4.3: Western Canadian Sectoral Demand
Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.262	0.190	0.500	0.952
1990	0.313	0.259	0.648	1.220
1995	0.328	0.297	0.639	1.264
2000	0.346	0.325	0.673	1.344
2005	0.375	0.354	0.724	1.453
2010	0.373	0.415	0.787	1.575
2015	0.394	0.446	0.827	1.667
2020	0.405	0.478	0.873	1.756
2025	0.420	0.513	0.896	1.829
2030	0.434	0.548	0.919	1.901

Table H4.4: Western Canadian Sectoral Demand
Burnertip Prices ($1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	4.88	4.16	3.48	3.79
1995	5.62	4.90	4.24	5.14
2000	6.22	5.50	4.84	5.65
2005	6.78	6.06	5.42	6.16
2010	7.42	6.70	6.07	6.57
2015	8.06	7.34	6.72	7.45
2020	9.23	8.51	7.91	8.57
2025	10.24	9.52	8.94	9.66
2030	11.89	11.17	10.63	11.32

Table B4.5: Ontario and Eastern Canadian Sectoral Demand Quantities (quadrillion BTU's)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Total	Total
1985	0.190	0.180	0.300	0.670	0.180
1990	0.239	0.261	0.401	0.901	2.404
1995	0.255	0.287	0.423	0.965	2.561
2000	0.253	0.314	0.458	1.025	2.765
2005	0.270	0.374	0.510	1.154	3.053
2010	0.290	0.434	0.563	1.287	3.379
2015	0.300	0.473	0.600	1.373	3.623
2020	0.311	0.518	0.644	1.472	3.863
2025	0.320	0.563	0.6795	1.562	4.096
2030	0.329	0.608	0.715	1.652	4.328

Table B4.6: Ontario and Eastern Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Average Price	Average Price
1990	5.99	4.97	4.40	4.99	4.78
1995	6.79	5.77	5.21	5.79	5.58
2000	7.41	6.39	5.84	6.40	6.19
2005	7.99	6.97	6.43	6.97	6.75
2010	8.66	7.64	7.11	7.64	7.41
2015	9.31	8.29	7.77	8.29	8.03
2020	10.48	9.46	8.97	9.46	9.23
2025	11.51	10.49	10.01	10.49	10.27
2030	13.10	12.04	11.63	12.09	11.87

Table B4.7: Canadian Exports by U.S Demand Region Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1985	0.510	0.000	0.390	0.000	0.900
1990	0.494	0.072	0.330	0.140	1.044
1995	0.355	0.049	0.228	0.142	0.814
2000	0.285	0.102	0.215	0.191	0.793
2005	0.250	0.118	0.263	0.309	0.940
2010	0.206	0.122	0.160	0.478	0.966
2015	0.171	0.106	0.239	0.850	1.376
2020	0.100	0.067	0.164	0.811	1.150
2025	0.073	0.045	0.1235	0.5705	0.812
2030	0.036	0.023	0.083	0.330	0.474

Table B4.8: Canadian Exports by U.S Demand Region Delivered Prices ($1987 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	4.44	4.47	5.20	5.40	4.83
1995	5.11	5.09	6.00	6.29	5.56
2000	5.69	5.67	6.61	6.92	6.23
2005	6.27	6.25	7.17	7.48	6.92
2010	6.87	6.85	7.82	8.14	7.65
2015	7.51	7.49	8.44	8.66	8.39
2020	8.69	8.68	9.58	9.79	9.39
2025	9.78	9.69	10.54	10.68	10.52
2030	11.45	11.49	12.06	12.29	12.15

Table H4.9: Competing Gas Sources in the Pacific Region Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.005	0.573	0.865	0.362	0.494	2.313
1995	0.031	0.666	1.103	0.245	0.355	2.416
2000	0.046	0.661	1.334	0.170	0.285	2.512
2005	0.059	0.659	1.411	0.116	0.250	2.509
2010	0.055	0.623	1.355	0.073	0.206	2.347
2015	0.060	0.575	1.422	0.048	0.171	2.303
2020	0.037	0.501	1.558	0.035	0.108	2.267
2025	0.025	0.3845	1.676	0.039	0.073	2.2315
2030	0.013	0.268	1.794	0.043	0.038	2.196

Table H4.10: Competing Gas Sources in the Pacific Region Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.74	3.99	3.90	4.50	4.44	4.11
1995	5.10	4.63	4.50	5.21	5.11	4.75
2000	5.79	5.29	5.06	5.92	5.69	5.28
2005	6.42	5.88	5.67	6.69	6.27	5.84
2010	7.14	6.44	6.20	7.50	6.87	6.38
2015	7.71	7.09	6.74	8.35	7.51	6.87
2020	9.33	7.68	7.16	8.65	8.69	7.41
2025	10.42	7.96	7.25	8.71	9.70	7.51
2030	11.94	8.53	7.38	8.67	11.45	7.51

Table H4.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	1.131	0.000	0.508	0.114	0.072	1.829
1995	1.197	0.000	0.307	0.098	0.089	1.697
2000	1.205	0.000	0.192	0.081	0.102	1.585
2005	1.165	0.000	0.124	0.065	0.118	1.478
2010	1.159	0.000	0.083	0.049	0.122	1.418
2015	1.183	0.001	0.054	0.035	0.108	1.386
2020	1.193	0.028	0.034	0.028	0.067	1.354
2025	0.975	0.2515	0.0235	0.025	0.045	1.3215
2030	0.757	0.475	0.013	0.022	0.023	1.289

Table H4.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.90	0.00	4.40	4.37	4.47	4.08
1995	4.50	0.00	5.10	5.04	5.09	4.65
2000	5.06	0.00	5.79	5.74	5.67	5.21
2005	5.66	0.00	6.51	6.40	6.25	5.79
2010	6.19	0.00	7.26	7.26	6.85	6.32
2015	6.73	8.99	8.14	8.09	7.49	6.86
2020	7.15	8.06	8.87	8.56	8.68	7.30
2025	7.23	7.41	9.11	8.43	9.69	7.40
2030	7.37	7.12	9.59	8.39	11.49	7.40

Table H4.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.686
1990	0.000	0.000	1.664	1.606	0.094	0.338	3.702
1995	0.000	0.000	1.438	1.498	0.070	0.228	3.234
2000	0.000	0.000	1.337	1.379	0.056	0.215	2.988
2005	0.000	0.000	1.230	1.227	0.048	0.263	2.768
2010	1.121	0.000	0.742	0.739	0.029	0.160	2.792
2015	1.285	0.013	0.616	0.502	0.024	0.239	2.678
2020	1.220	0.442	0.445	0.403	0.023	0.164	2.696
2025	1.207	1.279	0.340	0.309	0.019	0.124	3.276
2030	1.193	2.116	0.234	0.215	0.015	0.083	3.856

Table H4.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Averagu Price
1990	0.00	0.00	4.56	4.55	5.29	5.20	4.63
1995	0.00	0.00	5.27	5.25	6.08	6.00	5.33
2000	0.00	0.00	5.97	5.96	6.93	6.61	6.03
2005	0.00	14.40	6.71	6.73	7.78	7.17	6.78
2010	5.99	11.04	7.48	7.53	8.73	7.82	6.92
2015	7.98	9.37	8.37	8.44	9.62	8.44	8.24
2020	8.36	8.40	9.12	9.25	10.03	9.58	8.72
2025	8.00	7.73	9.37	9.36	10.06	10.54	8.27
2030	7.88	7.43	9.86	9.56	9.81	12.08	7.94

Table H4.15: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.908	0.376	0.010	0.140	2.433
1995	1.876	0.234	0.092	0.142	2.344
2000	1.939	0.169	0.136	0.191	2.435
2005	1.660	0.133	0.352	0.309	2.453
2010	1.379	0.248	0.512	0.478	2.617
2015	1.091	0.214	0.497	0.858	2.659
2020	1.111	0.297	0.493	0.811	2.712
2025	1.075	0.775	0.344	0.571	2.764
2030	1.038	1.253	0.194	0.330	2.815

Table H4.16: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.90	5.75	5.94	5.48	5.07
1995	5.55	6.49	6.10	6.29	5.71
2000	6.26	7.23	6.91	6.92	6.42
2005	7.15	8.02	7.35	7.48	7.27
2010	8.09	8.31	8.12	8.14	8.13
2015	8.99	9.55	9.10	8.66	8.95
2020	9.66	10.08	10.01	9.79	9.81
2025	9.67	9.67	11.12	10.68	10.06
2030	9.76	9.35	12.51	12.29	10.06

Table H4.17: Domestic Production by Region
(quadrillion BTU's)

Year	Alberta Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.807
1990	3.072	0.000	0.445	0.071	0.000	0.000	3.588
1995	2.736	0.085	0.583	0.112	0.000	0.000	3.516
2000	2.882	0.121	0.572	0.131	0.000	0.001	3.707
2005	3.258	0.134	0.599	0.129	0.000	0.045	4.165
2010	3.437	0.196	0.663	0.115	0.013	0.121	4.545
2015	3.435	0.218	0.675	0.090	0.164	0.677	5.259
2020	2.707	0.479	0.622	0.093	0.645	0.761	5.307
2025	2.255	0.905	0.567	0.099	0.666	0.578	5.069
2030	1.803	1.330	0.511	0.105	0.686	0.395	4.830

Table H4.18 Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

Year	Alberta Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Average Price
1990	3.00	4.19	3.18	3.48	0.00	10.81	3.03
1995	3.68	4.07	3.78	4.20	7.48	7.85	3.72
2000	4.27	4.72	4.34	4.85	6.10	6.43	4.32
2005	4.81	5.44	4.91	5.52	5.39	5.93	4.88
2010	5.45	5.99	5.49	6.36	5.17	6.48	5.53
2015	6.07	6.73	6.11	7.25	5.40	6.82	6.20
2020	7.31	7.55	7.27	8.49	5.64	7.85	7.22
2025	8.26	8.55	8.24	9.28	5.64	8.67	8.03
2030	10.07	9.65	10.04	11.38	5.74	10.13	9.37

Table H4.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.358	0.603	0.700	0.696	0.693	0.655	0.602	0.527	0.405	0.282
Rocky Mountains	1.504	2.169	2.500	2.761	2.801	2.733	2.841	3.202	3.274	3.346
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.434	2.195	3.956
Andarko	2.829	2.758	2.412	2.364	2.351	1.982	1.869	1.553	1.111	0.668
West Texas	1.478	1.516	1.379	1.399	1.288	1.169	1.358	2.207	3.093	3.979
Gulf Coast	9.406	9.125	8.114	8.004	7.557	6.836	6.200	5.093	3.560	2.026
Midwest	0.123	0.134	0.120	0.110	0.103	0.085	0.088	0.156	0.308	0.459
Appalachian	0.431	1.144	1.479	1.727	1.504	1.215	0.965	1.074	1.154	1.234
Total Lower 48	16.129	17.449	16.704	17.061	16.297	14.675	13.923	14.246	15.098	15.950
South Alaska	0.232	0.241	0.235	0.233	0.233	0.233	0.233	0.219	0.182	0.144
North Alaska	0.000	0.000	0.000	0.000	0.000	1.254	1.340	1.374	1.402	1.430
Total U.S	17.317	18.784	17.923	18.333	18.009	17.897	17.775	17.761	18.021	18.280

Table H4.20: U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.860	10.620	9.950	9.674	8.729	7.352	6.230	5.077	3.661	2.245
Lower 48 Offshore	4.713	5.064	4.868	4.955	4.554	4.077	3.559	2.741	1.918	1.095
Lower 48 Deep	1.555	1.756	1.886	2.431	3.012	3.208	3.549	3.432	2.575	1.717
Alaskan	0.232	0.241	0.235	0.233	0.233	1.488	1.573	1.593	1.584	1.574
Lurgi Coal Gas	0.000	0.000	0.000	0.000	0.002	0.037	0.594	2.987	6.928	10.868
Total	17.317	18.784	17.923	18.333	18.009	17.897	17.775	17.761	18.021	18.280

Table H4.21: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.23	3.83	4.48	5.05	5.58	6.22	6.79	7.07	7.63
Rocky Mountains	2.94	3.49	4.02	4.58	5.09	5.61	6.04	6.11	6.20
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	9.74	7.26	6.41	6.11
Andarko	3.49	4.15	4.80	5.48	6.18	7.00	7.69	7.95	8.51
West Texas	3.52	4.17	4.83	5.56	6.35	7.12	7.26	7.88	7.04
Gulf Coast	3.57	4.22	4.89	5.62	6.38	7.25	8.02	8.19	8.69
Midwest	4.32	5.08	5.87	6.67	7.60	8.50	8.85	8.89	8.67
Appalachian	3.63	4.38	5.11	6.02	6.95	7.90	8.53	8.50	8.55
Average	3.47	4.10	4.74	5.44	6.13	6.88	7.40	7.24	7.88

5. POLICY CASE: ROYALTY

Table H5.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports
1985	2.807	1.800	0.900
1990	3.720	2.314	1.263
1995	3.583	2.432	1.010
2000	3.739	2.613	0.978
2005	4.176	2.882	1.124
2010	4.518	3.196	1.127
2015	5.217	3.438	1.516
2020	5.249	3.685	1.274
2025	4.910	3.929	0.899
2030	4.571	4.173	0.524

Table H5.2 Summary Results for the U.S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.361	16.177	0.900	0.056	0.000
1990	17.502	17.640	1.263	0.039	0.010
1995	16.792	16.877	1.010	0.062	0.102
2000	17.160	17.292	0.978	0.086	0.153
2005	16.405	17.023	1.124	0.122	0.403
2010	16.068	16.911	1.127	0.148	0.603
2015	15.442	16.822	1.516	0.265	0.603
2020	15.768	16.762	1.274	0.158	0.601
2025	16.706	16.7045	0.899	0.1	0.418
2030	17.644	16.647	0.524	0.042	0.235

Table H5.3: Western Canadian Sectoral Demand
Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.260	0.190	0.500	0.950
1990	0.308	0.255	0.604	1.167
1995	0.319	0.288	0.585	1.192
2000	0.333	0.312	0.616	1.261
2005	0.359	0.339	0.665	1.363
2010	0.357	0.396	0.729	1.482
2015	0.377	0.426	0.771	1.574
2020	0.388	0.458	0.822	1.668
2025	0.404	0.493	0.851	1.748
2030	0.419	0.529	0.879	1.827

Table H5.4: Western Canadian Sectoral Demand
Burnertip Prices ($1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	5.33	4.61	3.93	3.84
1995	6.16	5.44	4.78	5.23
2000	6.81	6.09	5.44	5.71
2005	7.40	6.68	6.05	6.21
2010	8.04	7.32	6.70	6.62
2015	8.68	7.96	7.35	7.49
2020	9.83	9.11	8.53	8.56
2025	10.90	10.18	9.62	9.71
2030	12.43	11.71	11.18	11.22

Table H5.5: Ontario and Eastern Canadian Sectoral Demand Quantities (quadrillion BTU's)

	ONTARIO				
Year	Residential	Commercial	Industrial	Total	EASTERN CANADA Total
1985	0.190	0.180	0.300	0.670	0.180
1990	0.236	0.257	0.340	0.833	0.275
1995	0.248	0.280	0.400	0.928	0.318
2000	0.254	0.314	0.440	1.008	0.358
2005	0.260	0.361	0.490	1.111	0.423
2010	0.278	0.410	0.540	1.236	0.491
2015	0.288	0.450	0.570	1.316	0.554
2020	0.299	0.499	0.610	1.400	0.608
2025	0.309	0.544	0.650	1.503	0.679
2030	0.319	0.589	0.690	1.598	0.749

Table H5.6: Ontario and Eastern Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

	ONTARIO				
Year	Residential	Commercial	Industrial	Average Price	EASTERN CANADA Average Price
1990	6.43	5.41	4.84	5.47	5.21
1995	7.32	6.30	5.75	6.34	6.11
2000	8.01	6.99	6.45	7.01	6.78
2005	8.61	7.59	7.07	7.60	7.37
2010	9.28	8.26	7.75	8.27	8.03
2015	9.93	8.91	8.40	8.91	8.67
2020	11.10	10.00	9.59	10.00	9.84
2025	12.17	11.15	10.68	11.16	10.94
2030	13.58	12.56	12.12	12.57	12.44

Table H5.7: Canadian Exports by U.S Demand Region Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1995	0.510	0.000	0.390	0.000	0.900
1990	0.542	0.111	0.394	0.215	1.262
1995	0.401	0.127	0.277	0.205	1.010
2000	0.327	0.137	0.263	0.250	0.977
2005	0.280	0.150	0.318	0.367	1.123
2010	0.239	0.154	0.193	0.540	1.126
2015	0.199	0.134	0.277	0.983	1.513
2020	0.126	0.084	0.191	0.871	1.272
2025	0.085	0.056	0.146	0.611	0.898
2030	0.044	0.028	0.100	0.351	0.523

Table H5.8: Canadian Exports by U.S Demand Region Delivered Prices ($1987 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	4.15	4.18	4.88	5.17	4.55
1995	4.95	4.92	5.77	6.09	5.40
2000	5.57	5.52	6.45	6.78	6.11
2005	6.17	6.13	7.04	7.37	6.80
2010	6.76	6.71	7.69	8.03	7.52
2015	7.41	7.36	8.32	8.60	8.28
2020	8.50	8.55	9.46	9.70	9.48
2025	9.65	9.62	10.51	10.71	10.51
2030	11.25	11.26	11.98	12.26	12.07

Table H5.9: Competing Gas Sources in the Pacific Region
Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.005	0.561	0.843	0.362	0.542	2.313
1995	0.028	0.657	1.086	0.244	0.401	2.416
2000	0.042	0.654	1.319	0.169	0.327	2.512
2005	0.053	0.651	1.400	0.114	0.288	2.509
2010	0.049	0.619	1.344	0.072	0.239	2.347
2015	0.054	0.570	1.414	0.047	0.199	2.303
2020	0.034	0.503	1.551	0.034	0.126	2.267
2025	0.023	0.388	1.670	0.038	0.085	2.232
2030	0.012	0.272	1.788	0.042	0.044	2.196

Table H5.10: Competing Gas Sources in the Pacific Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.74	3.96	3.87	4.49	4.15	4.06
1995	5.10	4.59	4.46	5.18	4.95	4.72
2000	5.79	5.25	5.02	5.90	5.57	5.27
2005	6.42	5.84	5.62	6.66	6.17	5.83
2010	7.14	6.39	6.16	7.46	6.76	6.36
2015	7.71	7.05	6.70	8.31	7.41	6.87
2020	9.33	7.63	7.14	8.83	8.58	7.41
2025	10.42	7.92	7.24	8.71	9.65	7.53
2030	11.94	8.50	7.39	8.68	11.25	7.53

Table H5.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	1.101	0.000	0.506	0.111	0.111	1.829
1995	1.170	0.000	0.305	0.094	0.127	1.697
2000	1.181	0.000	0.190	0.077	0.137	1.585
2005	1.144	0.000	0.122	0.062	0.150	1.478
2010	1.137	0.000	0.081	0.046	0.154	1.418
2015	1.165	0.000	0.053	0.033	0.134	1.386
2020	1.183	0.027	0.034	0.026	0.084	1.354
2025	0.970	0.249	0.024	0.024	0.056	1.322
2030	0.756	0.471	0.013	0.022	0.028	1.289

Table H5.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.79	0.00	4.30	4.27	3.97	3.97
1995	4.38	0.00	5.00	4.96	4.71	4.55
2000	4.93	0.00	5.68	5.64	5.30	5.09
2005	5.52	0.00	6.39	6.37	5.88	5.66
2010	6.07	0.00	7.12	7.13	6.53	6.21
2015	6.60	0.00	8.00	7.96	7.37	6.76
2020	7.07	8.06	8.76	8.52	8.67	7.26
2025	7.20	7.43	9.05	8.43	9.51	7.40
2030	7.37	7.13	9.59	8.41	11.38	7.42

Table H5.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.686
1990	0.000	0.000	1.645	1.659	0.094	0.394	3.792
1995	0.000	0.000	1.424	1.473	0.069	0.277	3.244
2000	0.000	0.000	1.323	1.352	0.056	0.263	2.994
2005	0.000	0.000	1.210	1.197	0.047	0.318	2.772
2010	1.119	0.000	0.727	0.718	0.028	0.193	2.785
2015	1.203	0.012	0.599	0.563	0.023	0.277	2.677
2020	1.219	0.429	0.435	0.391	0.022	0.191	2.688
2025	1.208	1.323	0.337	0.304	0.019	0.146	3.336
2030	1.197	2.216	0.238	0.217	0.016	0.100	3.983

Table H5.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Average Price
1990	0.00	0.00	4.53	4.53	5.26	4.88	4.58
1995	0.00	0.00	5.24	5.22	6.05	5.77	5.29
2000	0.00	0.00	5.94	5.93	6.90	6.45	6.00
2005	0.00	14.37	6.67	6.69	7.73	7.04	6.74
2010	5.92	11.00	7.44	7.50	8.68	7.69	6.87
2015	7.92	9.35	8.33	8.40	9.58	8.32	8.17
2020	8.34	8.40	9.08	9.22	10.01	9.46	8.69
2025	8.00	7.73	9.35	9.35	10.06	10.51	8.27
2030	7.96	7.43	9.86	9.56	9.83	11.98	7.98

Table H5.15: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.840	0.376	0.010	0.215	2.440
1995	1.823	0.233	0.091	0.205	2.352
2000	1.892	0.167	0.135	0.250	2.444
2005	1.620	0.129	0.348	0.367	2.464
2010	1.351	0.233	0.506	0.540	2.630
2015	1.073	0.204	0.492	0.903	2.673
2020	1.081	0.282	0.489	0.871	2.723
2025	1.063	0.755	0.340	0.611	2.768
2030	1.044	1.227	0.191	0.351	2.813

Table H5.16: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.86	5.70	5.88	5.17	5.02
1995	5.51	6.46	6.05	6.09	5.68
2000	6.21	7.20	6.85	6.78	6.37
2005	7.09	7.99	7.28	7.37	7.21
2010	8.01	8.26	8.05	8.03	8.04
2015	8.93	9.48	9.05	8.60	8.88
2020	9.63	10.05	9.97	9.70	9.76
2025	9.68	9.68	11.12	10.71	10.08
2030	9.77	9.40	12.51	12.26	10.11

Table H5.17: Domestic Production by Region
(quadrillion BTU's)

	Alberta						
Year	Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.807
1990	3.228	0.000	0.422	0.070	0.000	0.000	3.720
1995	2.780	0.081	0.606	0.115	0.000	0.000	3.582
2000	2.876	0.120	0.603	0.139	0.000	0.002	3.740
2005	3.260	0.127	0.621	0.131	0.001	0.035	4.175
2010	3.401	0.175	0.680	0.115	0.052	0.095	4.518
2015	3.307	0.188	0.667	0.089	0.373	0.593	5.217
2020	2.736	0.390	0.594	0.086	0.654	0.787	5.247
2025	2.271	0.733	0.542	0.093	0.672	0.599	4.909
2030	1.806	1.075	0.490	0.099	0.690	0.410	4.570

Table H5.18: Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

	Alberta						
Year	Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Average Price
1990	2.73	3.97	3.07	3.42	0.00	10.86	2.78
1995	3.44	3.81	3.67	4.12	7.58	7.86	3.51
2000	3.97	4.39	4.16	4.74	6.21	6.41	4.04
2005	4.43	5.04	4.66	5.40	5.54	5.88	4.53
2010	4.97	5.48	5.14	6.14	5.43	6.43	5.08
2015	5.49	6.07	5.67	6.88	5.65	6.80	5.72
2020	6.46	6.76	6.63	8.01	5.76	7.77	6.64
2025	7.31	7.57	7.51	8.70	5.75	8.71	7.35
2030	8.65	8.44	8.87	10.40	5.87	10.14	8.38

Table H5.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.358	0.589	0.691	0.688	0.605	0.651	0.600	0.528	0.41	0.286
Rocky Mountains	1.504	2.113	2.453	2.718	2.766	2.697	2.811	3.180	3.27	3.361
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.007	0.414	2.22	4.032
Andarko	2.829	2.735	2.397	2.352	2.331	1.972	1.864	1.558	1.12	0.603
West Texas	1.478	1.510	1.373	1.395	1.282	1.165	1.339	2.179	3.07	3.957
Gulf Coast	9.406	9.073	8.078	7.964	7.514	6.794	6.195	5.108	3.58	2.058
Midwest	0.123	0.133	0.119	0.109	0.103	0.085	0.087	0.152	0.38	0.451
Appalachian	0.431	1.106	1.446	1.702	1.490	1.218	0.968	1.058	1.15	1.239
Total Lower 48	16.128	15.482	15.755	16.447	15.817	14.364	13.385	14.191	15.10	16.000
South Alaska	0.232	0.241	0.235	0.233	0.233	0.233	0.233	0.218	0.18	0.144
North Alaska	0.000	0.000	0.000	0.000	0.000	1.251	1.338	1.373	1.40	1.432
Total U.S	17.317	18.814	17.966	18.377	18.054	17.946	17.826	17.801	18.12	18.445

Table H5.20: U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.860	10.496	9.847	9.595	8.668	7.328	6.235	5.105	3.811	2.290
Lower 48 Offshore	4.713	5.027	4.842	4.927	4.530	4.053	3.565	2.753	1.987	1.112
Lower 48 Deep	1.555	1.738	1.868	2.406	2.972	3.168	3.519	3.435	2.469	1.751
Alaskan	0.232	0.241	0.235	0.233	0.233	1.485	1.571	1.591	1.574	1.577
Lurgi Coal Gas	0.000	0.000	0.000	0.000	0.001	0.033	0.551	2.875	6.640	10.889
Total	17.317	18.814	17.966	18.377	18.054	17.946	17.826	17.801	18.12	18.445

Table H5.21: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.23	3.83	4.48	5.05	5.58	6.22	6.79	7.07	7.63
Rocky Mountains	2.94	3.49	4.02	4.58	5.09	5.61	6.04	6.11	6.20
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	9.74	7.26	6.41	6.11
Andarko	3.49	4.15	4.80	5.48	6.18	7.00	7.69	7.95	8.51
West Texas	3.52	4.17	4.83	5.56	6.35	7.12	7.26	7.08	7.04
Gulf Coast	3.57	4.22	4.89	5.62	6.38	7.25	8.02	8.19	8.69
Midwest	4.32	5.08	5.87	6.67	7.60	8.50	8.85	8.89	8.67
Appalachian	3.63	4.38	5.11	6.02	6.95	7.90	8.53	8.50	8.55
Average	3.87	4.31	4.88	5.56	6.22	7.13	7.39	7.25	7.11

6. SENSITIVITY CASE: UPCON

Table H6.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports to U.S.
1985	2.007	1.000	0.900
1990	4.300	2.373	1.772
1995	4.267	2.519	1.604
2000	4.587	2.721	1.608
2005	5.146	3.005	1.940
2010	5.304	3.324	1.839
2015	5.891	3.456	2.072
2020	5.819	3.775	1.733
2025	5.452	4.020	1.228
2030	5.085	4.265	0.722

Table H6.2: Summary Results for the U.S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.361	16.177	0.900	0.056	0.000
1990	17.004	17.763	1.772	0.036	0.010
1995	16.362	17.063	1.604	0.048	0.101
2000	16.654	17.516	1.608	0.063	0.152
2005	15.820	17.270	1.940	0.087	0.400
2010	15.640	17.161	1.839	0.108	0.553
2015	15.194	17.062	2.072	0.196	0.567
2020	15.561	16.951	1.733	0.119	0.546
2025	16.406	16.818	1.228	0.076	0.379
2030	17.250	16.605	0.722	0.032	0.212

Table H6.3: Western Canadian Sectoral Demand
Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.260	0.190	0.500	0.950
1990	0.311	0.258	0.632	1.201
1995	0.325	0.294	0.621	1.240
2000	0.342	0.321	0.656	1.319
2005	0.370	0.349	0.707	1.426
2010	0.369	0.409	0.769	1.547
2015	0.388	0.439	0.801	1.628
2020	0.398	0.469	0.845	1.712
2025	0.413	0.505	0.875	1.792
2030	0.420	0.540	0.904	1.872

Table H6.4: Western Canadian Sectoral Demand
Burnertip Prices (@1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	5.04	4.32	3.64	4.15
1995	5.79	5.07	4.41	4.93
2000	6.37	5.65	5.00	5.51
2005	6.95	6.23	5.59	6.10
2010	7.61	6.89	6.26	6.75
2015	8.40	7.68	7.07	7.55
2020	9.56	8.04	8.26	8.72
2025	10.48	9.76	9.19	9.65
2030	12.00	11.36	10.83	11.27

Table H6.5: Ontario and Eastern Canadian Sectoral Demand Quantities (quadrillion BTU's)

		ONTARIO			EASTERN CANADA
Year	Residential	Commercial	Industrial	Total	Total
1985	0.190	0.180	0.300	0.670	0.188
1990	0.238	0.260	0.393	0.891	0.281
1995	0.253	0.285	0.414	0.952	0.327
2000	0.259	0.322	0.450	1.031	0.371
2005	0.268	0.370	0.501	1.139	0.440
2010	0.286	0.430	0.552	1.268	0.509
2015	0.296	0.469	0.583	1.348	0.570
2020	0.306	0.509	0.626	1.441	0.622
2025	0.315	0.555	0.666	1.536	0.693
2030	0.325	0.600	0.705	1.630	0.764

Table H6.6: Ontario and Eastern Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

		ONTARIO			EASTERN CANADA
Year	Residential	Commercial	Industrial	Average Price	Average Price
1990	6.13	5.11	4.54	5.13	4.92
1995	6.94	5.92	5.37	5.95	5.73
2000	7.55	6.53	5.98	6.55	6.32
2005	8.16	7.14	6.60	7.14	6.91
2010	8.84	7.82	7.30	7.83	7.59
2015	9.64	8.62	8.11	8.62	8.38
2020	10.81	9.79	9.28	9.79	9.56
2025	11.76	10.74	10.26	10.74	10.51
2030	13.29	12.27	11.82	12.28	12.06

Table H6.7: Canadian Exports by U.S Demand Region Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1985	0.310	0.000	0.290	0.000	0.600
1990	0.668	0.193	0.552	0.358	1.771
1995	0.346	0.225	0.462	0.370	1.403
2000	0.489	0.241	0.499	0.438	1.667
2005	0.462	0.260	0.609	0.606	1.937
2010	0.390	0.237	0.366	0.823	1.816
2015	0.230	0.287	0.427	1.124	2.068
2020	0.196	0.129	0.302	1.103	1.730
2025	0.132	0.086	0.226	0.782	1.225
2030	0.068	0.043	0.149	0.468	0.728

Table H6.8: Canadian Exports by U.S Demand Region Delivered Prices ($1985 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	2.86	3.92	4.59	4.87	4.28
1995	4.63	4.62	5.40	5.70	5.10
2000	5.21	5.20	5.99	6.31	5.74
2005	5.78	5.76	6.58	6.91	6.30
2010	6.41	6.38	7.25	7.60	7.11
2015	7.20	7.17	8.04	8.36	8.00
2020	8.30	8.27	9.20	9.46	9.21
2025	9.24	9.21	10.13	10.30	10.13
2030	10.94	10.90	11.66	11.97	11.75

Table H6.9: Competing Gas Sources in the Pacific Region
Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.003	0.526	0.780	0.362	0.668	2.338
1995	0.018	0.620	1.022	0.241	0.546	2.456
2000	0.027	0.628	1.246	0.165	0.489	2.557
2005	0.035	0.616	1.331	0.109	0.462	2.556
2010	0.033	0.595	1.285	0.068	0.390	2.338
2015	0.037	0.563	1.369	0.044	0.310	2.338
2020	0.023	0.512	1.516	0.032	0.196	2.294
2025	0.016	0.403	1.636	0.036	0.132	2.249
2030	0.008	0.294	1.756	0.039	0.068	2.203

Table H6.10: Competing Gas Sources in the Pacific Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.74	3.86	3.77	4.41	3.86	3.92
1995	5.10	4.46	4.34	5.10	4.63	4.57
2000	5.79	5.10	4.89	5.78	5.21	5.11
2005	6.42	5.69	5.46	6.53	5.78	5.65
2010	7.14	6.23	6.01	7.31	6.41	6.20
2015	7.71	6.87	6.55	8.16	7.20	6.90
2020	9.33	7.48	7.04	8.76	8.38	7.35
2025	10.42	7.81	7.20	8.71	9.24	7.52
2030	11.94	8.42	7.39	8.70	10.94	7.55

Table H6.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	1.043	0.000	0.504	0.103	0.193	1.844
1995	1.108	0.000	0.302	0.084	0.225	1.719
2000	1.115	0.000	0.186	0.068	0.241	1.609
2005	1.073	0.000	0.117	0.052	0.260	1.503
2010	1.069	0.000	0.077	0.040	0.257	1.442
2015	1.119	0.000	0.050	0.029	0.207	1.406
2020	1.163	0.021	0.032	0.023	0.129	1.368
2025	0.963	0.236	0.022	0.022	0.086	1.329
2030	0.763	0.451	0.012	0.020	0.043	1.290

Table H6.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.77	0.00	4.30	4.28	3.92	3.96
1995	4.34	0.00	4.97	4.94	4.62	4.52
2000	4.89	0.00	5.63	5.60	5.20	5.06
2005	5.45	0.00	6.34	6.32	5.76	5.60
2010	6.01	0.00	7.06	7.07	6.38	6.17
2015	6.54	8.91	7.92	7.90	7.17	6.71
2020	7.02	8.06	8.70	8.48	8.37	7.23
2025	7.19	7.44	9.01	8.43	9.21	7.41
2030	7.38	7.14	9.57	8.42	10.98	7.45

Table H6.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.686
1990	0.000	0.000	1.593	1.579	0.092	0.552	3.815
1995	0.000	0.000	1.370	1.373	0.067	0.462	3.273
2000	0.000	0.000	1.250	1.222	0.053	0.499	2.023
2005	0.000	0.000	1.098	1.047	0.043	0.609	2.797
2010	1.100	0.000	0.651	0.619	0.026	0.366	2.761
2015	1.200	0.008	0.532	0.483	0.021	0.427	2.671
2020	1.220	0.375	0.403	0.347	0.020	0.302	2.667
2025	1.207	1.172	0.307	0.266	0.017	0.226	3.193
2030	1.193	1.969	0.210	0.184	0.013	0.149	3.719

Table H6.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Average Price
1990	0.00	0.00	4.45	4.46	5.17	4.59	4.49
1995	0.00	0.00	5.14	5.14	5.94	5.40	5.19
2000	0.00	0.00	5.81	5.83	6.75	5.99	8.77
2005	0.00	14.22	6.53	6.56	7.57	6.58	6.57
2010	5.88	10.88	7.27	7.36	8.49	7.25	6.75
2015	7.70	9.28	8.15	8.23	9.40	8.04	7.96
2020	8.28	8.40	8.94	9.08	9.94	9.20	8.62
2025	8.00	7.76	9.26	9.28	10.02	10.13	8.30
2030	7.92	7.45	9.83	9.55	9.90	11.66	8.01

Table H6.15: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.718	0.375	0.009	0.358	2.460
1995	1.695	0.230	0.089	0.370	2.383
2000	1.737	0.160	0.130	0.458	2.485
2005	1.460	0.117	0.330	0.606	2.514
2010	1.244	0.179	0.442	0.823	2.688
2015	0.997	0.166	0.441	1.124	2.729
2020	0.995	0.239	0.429	1.103	2.767
2025	1.000	0.715	0.298	0.782	2.795
2030	1.005	1.190	0.167	0.460	2.822

Table H6.16: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.76	5.59	5.69	4.87	4.91
1995	5.36	6.34	5.87	5.70	5.53
2000	6.02	7.05	6.61	6.31	6.17
2005	6.85	7.80	7.00	6.91	6.93
2010	7.72	8.12	7.84	7.60	7.73
2015	8.70	9.26	8.80	8.36	8.61
2020	9.53	9.96	9.09	9.46	9.59
2025	9.66	9.70	11.12	10.38	10.03
2030	9.81	9.44	12.51	11.97	10.17

Table H6.17: Domestic Production by Region
(quadrillion BTU's)

Year	Alberta Conventional	'Tight' Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.807
1990	3.750	0.000	0.483	0.075	0.000	0.000	4.308
1995	3.414	0.091	0.668	0.115	0.000	0.000	4.288
2000	3.644	0.130	0.675	0.134	0.000	0.003	4.586
2005	4.116	0.149	0.738	0.132	0.000	0.011	5.146
2010	4.221	0.218	0.777	0.116	0.016	0.036	5.384
2015	4.123	0.272	0.698	0.096	0.215	0.487	5.891
2020	3.128	0.543	0.562	0.097	0.651	0.838	5.819
2025	2.605	0.944	0.501	0.100	0.670	0.635	5.453
2030	2.081	1.344	0.439	0.102	0.688	0.432	5.086

Table H6.18: Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

Year	Alberta Conventional	'Tight' Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Average Price
1990	3.03	4.33	3.41	3.58	0.00	10.81	3.08
1995	3.83	4.23	4.08	4.32	7.53	7.79	3.89
2000	4.39	4.93	4.65	5.00	6.14	6.30	4.46
2005	4.97	5.62	5.19	5.73	5.43	5.69	5.04
2010	5.63	6.21	5.79	6.60	5.23	6.26	5.70
2015	6.41	7.00	6.56	7.53	5.47	6.64	6.46
2020	7.63	7.83	7.73	8.71	5.67	7.58	7.45
2025	8.48	8.82	8.54	9.64	5.67	8.43	8.21
2030	10.21	9.92	10.30	11.63	5.77	9.90	9.54

Table H6.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.358	0.554	0.661	0.661	0.648	0.625	0.592	0.539	0.424	0.309
Rocky Mountains	1.504	1.981	2.315	2.567	2.612	2.556	2.709	3.104	3.220	3.335
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.005	0.341	2.010	3.679
Anderko	2.829	2.684	2.351	2.299	2.234	1.930	1.855	1.589	1.160	0.730
West Texas	1.478	1.492	1.352	1.375	1.258	1.147	1.274	2.064	2.946	3.828
Gulf Coast	9.406	8.959	7.958	7.795	7.313	6.624	6.134	5.180	3.687	2.193
Midwest	0.123	0.132	0.118	0.108	0.100	0.083	0.084	0.137	0.269	0.401
Appalachian	0.431	1.041	1.372	1.616	1.422	1.225	0.978	1.021	1.111	1.200
Total Lower 48	16.129	16.843	16.127	16.421	15.587	14.190	13.631	13.975	14.825	15.675
South Alaska	0.232	0.241	0.235	0.233	0.233	0.233	0.232	0.217	0.181	0.145
North Alaska	0.000	0.000	0.000	0.000	0.000	1.224	1.331	1.371	1.401	1.431
Total U.S	17.317	18.902	18.115	18.557	18.247	18.148	18.029	17.959	18.088	18.216

Table H6.20: U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.860	10.210	9.559	9.306	8.370	7.214	6.266	5.245	3.845	2.444
Lower 48 Offshore	4.713	4.940	4.756	4.808	4.412	3.948	3.547	2.809	2.000	1.190
Lower 48 Deep	1.555	1.692	1.812	2.306	2.803	3.006	3.406	3.451	2.661	1.871
Alaskan	0.232	0.241	0.235	0.233	0.233	1.457	1.563	1.588	1.582	1.575
Lurgi Coal Gas	0.000	0.000	0.000	0.000	0.001	0.022	0.411	2.460	6.304	10.148
Total	17.317	18.902	18.115	18.557	18.247	18.148	18.029	17.959	18.088	18.216

Table H6.21: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.13	3.70	4.34	4.90	5.43	6.05	6.64	6.96	7.55
Rocky Mountains	2.84	3.38	3.89	4.43	4.95	5.47	5.94	6.08	6.21
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	10.00	7.32	6.42	6.12
Anderko	3.41	4.06	4.68	5.35	6.03	6.83	7.56	7.87	8.46
West Texas	3.46	4.09	4.73	5.45	6.21	7.01	7.23	7.07	7.03
Gulf Coast	3.50	4.14	4.79	5.50	6.25	7.09	7.89	8.12	8.65
Midwest	4.24	4.97	5.74	6.51	7.41	8.34	8.77	8.82	8.71
Appalachian	3.50	4.22	4.93	5.77	6.64	7.66	8.46	8.51	8.59
Average	3.40	4.01	4.63	5.30	5.99	6.73	7.31	7.23	7.11

7. SENSITIVITY CASE: TINC

Table H7.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports to U.S.
1985	2.807	1.800	0.900
1990	4.163	2.361	1.643
1995	4.119	2.502	1.458
2000	4.424	2.704	1.548
2005	5.008	2.987	1.824
2010	5.340	3.313	1.806
2015	5.812	3.530	2.001
2020	5.815	3.775	1.730
2025	5.569	4.072	1.243
2030	5.322	4.368	0.756

Table H7.2: Summary Results for the U.S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.361	16.177	0.900	0.056	0.000
1990	17.200	17.741	1.643	0.037	0.010
1995	16.484	17.031	1.458	0.050	0.102
2000	16.764	17.482	1.548	0.066	0.153
2005	15.904	17.235	1.824	0.091	0.401
2010	15.642	17.131	1.806	0.111	0.560
2015	15.219	17.033	2.001	0.203	0.581
2020	15.539	16.933	1.730	0.122	0.549
2025	16.331	16.818	1.243	0.078	0.381
2030	17.122	16.703	0.756	0.033	0.212

Table H7.3: Western Canadian Sectoral Demand Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.260	0.190	0.500	0.950
1990	0.311	0.257	0.627	1.195
1995	0.324	0.293	0.614	1.231
2000	0.340	0.320	0.650	1.310
2005	0.368	0.348	0.702	1.418
2010	0.367	0.408	0.767	1.542
2015	0.387	0.437	0.795	1.619
2020	0.397	0.468	0.846	1.711
2025	0.415	0.507	0.894	1.816
2030	0.433	0.547	0.941	1.921

Table h7.4: Western Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	5.09	4.37	3.69	3.56
1995	5.85	5.13	4.47	4.89
2000	6.42	5.70	5.05	5.31
2005	7.01	6.29	5.65	5.83
2010	7.61	6.89	6.27	6.22
2015	8.48	7.76	7.15	7.37
2020	9.49	8.77	8.18	8.24
2025	10.18	9.46	8.88	8.90
2030	11.41	10.69	10.14	10.11

Table H7.5: Ontario and Eastern Canadian Sectoral Demand Quantities (quadrillion BTU's)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Total	Total
1985	0.190	0.180	0.300	0.670	0.180
1990	0.238	0.259	0.390	0.887	0.279
1995	0.252	0.284	0.410	0.946	0.325
2000	0.258	0.321	0.446	1.025	0.369
2005	0.266	0.369	0.497	1.132	0.437
2010	0.286	0.428	0.550	1.264	0.508
2015	0.295	0.468	0.580	1.343	0.568
2020	0.305	0.509	0.628	1.442	0.622
2025	0.317	0.558	0.680	1.555	0.701
2030	0.329	0.607	0.731	1.667	0.780

Table H7.6: Ontario and Eastern Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Average Price	Average Price
1990	6.19	5.17	4.60	5.19	4.97
1995	7.01	5.99	5.43	6.02	5.80
2000	7.61	6.59	6.04	6.61	6.38
2005	8.22	7.20	6.67	7.21	6.97
2010	8.85	7.83	7.30	7.83	7.59
2015	9.71	8.69	8.18	8.69	8.45
2020	10.73	9.71	9.22	9.71	9.49
2025	11.44	10.42	9.94	10.42	10.20
2030	12.64	11.62	11.16	11.62	11.39

Table H7.7: Canadian Exports by U.S Demand Region Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1985	0.510	0.000	0.390	0.000	0.900
1990	0.632	0.184	0.506	0.320	1.642
1995	0.507	0.214	0.409	0.326	1.456
2000	0.454	0.232	0.446	0.414	1.546
2005	0.43[illegible]	0.261	0.556	0.565	1.821
2010	0.387	0.268	0.334	0.813	1.802
2015	0.290	0.202	0.387	1.118	1.997
2020	0.188	0.127	0.285	1.128	1.728
2025	0.120	0.085	0.212	0.817	1.241
2030	0.067	0.043	0.139	0.505	0.754

Table H7.8: Canadian Exports by U.S Demand Region Delivered Prices ($1987 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	3.91	3.96	4.64	4.93	4.34
1995	4.68	4.65	5.46	5.77	5.14
2000	5.25	5.23	6.04	6.37	5.77
2005	5.80	5.76	6.64	6.98	6.42
2010	6.39	6.35	7.25	7.60	7.09
2015	7.29	7.28	8.11	8.36	8.05
2020	8.31	8.30	9.13	9.42	9.17
2025	8.96	8.94	9.84	10.13	9.88
2030	10.28	10.35	11.00	11.33	11.12

Table H7.9: Competing Gas Sources in the Pacific Region
Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.003	0.537	0.801	0.362	0.632	2.334
1995	0.019	0.636	1.045	0.242	0.507	2.450
2000	0.029	0.634	1.268	0.165	0.454	2.551
2005	0.036	0.619	1.344	0.110	0.439	2.551
2010	0.033	0.592	1.286	0.068	0.387	2.385
2015	0.039	0.565	1.382	0.045	0.290	2.335
2020	0.024	0.511	1.522	0.032	0.188	2.292
2025	0.016	0.401	1.642	0.036	0.128	2.249
2030	0.008	0.291	1.761	0.040	0.067	2.205

Table H7.10: Competing Gas Sources in the Pacific Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.74	3.87	3.78	4.43	3.91	3.94
1995	5.10	4.48	4.36	5.11	4.68	4.59
2000	5.79	5.12	4.91	5.80	5.25	5.13
2005	6.42	5.70	5.47	6.55	5.80	5.66
2010	7.14	6.24	6.03	7.33	6.39	6.21
2015	7.71	6.89	6.57	8.18	7.29	6.78
2020	9.33	7.49	7.04	8.77	8.31	7.34
2025	10.42	7.82	7.20	8.71	8.96	7.49
2030	11.94	8.42	7.39	8.70	10.28	7.53

Table H7.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	1.050	0.000	0.504	0.104	0.184	1.842
1995	1.116	0.000	0.301	0.085	0.214	1.716
2000	1.120	0.000	0.186	0.068	0.232	1.606
2005	1.070	0.000	0.116	0.052	0.261	1.500
2010	1.056	0.000	0.076	0.039	0.268	1.440
2015	1.122	0.000	0.050	0.029	0.202	1.403
2020	1.163	0.021	0.032	0.023	0.127	1.366
2025	0.963	0.237	0.022	0.022	0.085	1.329
2030	0.763	0.453	0.012	0.020	0.043	1.292

Table H7.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.78	0.00	4.31	4.29	3.96	3.97
1995	4.36	0.00	4.99	4.95	4.65	4.54
2000	4.90	0.00	5.65	5.62	5.23	5.07
2005	5.47	0.00	6.36	6.34	5.76	5.62
2010	6.02	0.00	7.08	7.10	6.35	6.16
2015	6.56	8.92	7.94	7.92	7.28	6.74
2020	7.03	8.06	8.71	8.49	8.30	7.23
2025	7.19	7.43	9.01	8.43	8.94	7.39
2030	7.37	7.14	9.56	8.42	10.35	7.42

Table H7.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.686
1990	0.000	0.000	1.610	1.602	0.093	0.506	3.811
1995	0.000	0.000	1.389	1.401	0.068	0.409	3.267
2000	0.000	0.000	1.268	1.250	0.054	0.446	3.017
2005	0.000	0.000	1.119	1.074	0.044	0.556	2.792
2010	1.099	0.000	0.663	0.634	0.026	0.334	2.756
2015	1.201	0.009	0.546	0.498	0.021	0.387	2.662
2020	1.220	0.371	0.407	0.353	0.020	0.285	2.657
2025	1.207	1.133	0.307	0.268	0.017	0.212	3.144
2030	1.193	1.895	0.207	0.183	0.013	0.139	3.630

Table H7.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Average Price
1990	0.00	0.00	4.46	4.47	5.19	4.64	4.51
1995	0.00	0.00	5.16	5.15	5.96	5.46	5.21
2000	0.00	0.00	5.83	5.84	6.78	6.04	5.88
2005	0.00	14.23	6.55	6.58	7.59	6.64	6.60
2010	5.88	10.89	7.29	7.38	8.52	7.25	6.76
2015	7.74	9.29	8.17	8.25	9.43	8.11	8.00
2020	8.28	8.40	8.96	9.10	9.95	9.13	8.61
2025	7.99	7.75	9.27	9.29	10.02	9.84	8.27
2030	7.87	7.45	9.83	9.55	9.89	11.00	7.97

Table H7.15: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.751	0.375	0.009	0.320	2.456
1995	1.731	0.230	0.090	0.326	2.378
2000	1.771	0.161	0.132	0.414	2.479
2005	1.489	0.118	0.333	0.565	2.506
2010	1.243	0.178	0.448	0.813	2.682
2015	0.992	0.163	0.451	1.118	2.724
2020	0.997	0.233	0.428	1.128	2.766
2025	0.981	0.716	0.297	0.817	2.801
2030	0.965	1.198	0.166	0.505	2.835

Table H7.16: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.77	5.61	5.61	4.93	4.92
1995	5.38	6.36	5.78	5.77	5.54
2000	6.05	7.07	6.52	6.37	6.19
2005	6.89	7.83	6.98	6.98	6.96
2010	7.76	8.13	7.84	7.60	7.75
2015	8.73	9.30	8.80	8.36	8.62
2020	9.52	9.96	9.89	9.42	9.64
2025	9.65	9.67	11.12	10.13	9.98
2030	9.80	9.39	12.51	11.33	10.05

Table H7.17: Domestic Production by Region
(quadrillion BTU's)

Year	Alberta Conventional	Alberta "Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.807
1990	3.567	0.013	0.506	0.077	0.000	0.000	4.163
1995	3.108	0.193	0.695	0.123	0.000	0.000	4.119
2000	3.330	0.252	0.698	0.142	0.000	0.002	4.424
2005	3.730	0.325	0.804	0.135	0.000	0.015	5.009
2010	3.897	0.443	0.837	0.115	0.014	0.035	5.341
2015	3.358	0.653	0.695	0.101	0.234	0.771	5.812
2020	2.582	1.152	0.560	0.107	0.649	0.764	5.814
2025	2.073	1.675	0.480	0.100	0.664	0.577	5.568
2030	1.563	2.198	0.399	0.093	0.679	0.389	5.321

Table H7.18: Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

Year	Alberta Conventional	Alberta "Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Average Price
1990	3.09	4.37	3.44	3.64	0.00	10.81	3.15
1995	3.90	4.17	4.12	4.38	7.53	7.78	3.96
2000	4.45	4.86	4.67	5.04	6.14	6.29	4.53
2005	5.03	5.48	5.19	5.80	5.44	5.66	5.11
2010	5.63	6.05	5.77	6.63	5.24	6.28	5.71
2015	6.51	6.77	6.67	7.59	5.48	6.57	6.54
2020	7.63	7.51	7.66	8.57	5.67	7.56	7.40
2025	8.25	8.26	8.28	9.38	5.66	8.23	7.96
2030	9.80	9.09	9.69	11.03	5.76	9.34	8.97

Table #7.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.250	0.364	0.669	0.666	0.651	0.623	0.594	0.537	0.422	0.306
Rocky Mountains	1.504	2.011	2.348	2.596	2.623	2.544	2.728	3.109	3.217	3.325
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.005	0.341	1.979	3.616
Anadarko	2.029	2.701	2.366	2.311	2.249	1.933	1.857	1.502	1.151	0.720
West Texas	1.478	1.497	1.357	1.379	1.262	1.149	1.288	2.076	2.958	3.840
Gulf Coast	9.406	8.993	7.993	7.831	7.346	6.641	6.139	5.163	3.667	2.170
Midwest	0.123	0.133	0.119	0.100	0.100	0.083	0.085	0.138	0.272	0.405
Appalachian	0.431	1.060	1.397	1.648	1.439	1.213	0.960	1.085	1.086	1.166
Total Lower 48	16.129	16.959	16.249	16.531	15.670	14.186	13.656	13.951	14.750	15.548
South Alaska	0.232	0.241	0.235	0.233	0.233	0.233	0.232	0.217	0.181	0.145
North Alaska	0.000	0.000	0.000	0.000	0.000	1.222	1.332	1.371	1.400	1.429
Total U.S	17.317	18.090	18.094	18.531	18.220	18.119	18.004	17.940	18.032	18.123

Table #7.20: U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.060	10.285	9.641	9.272	8.416	7.192	6.259	5.217	3.817	2.416
Lower 48 Offshore	4.713	4.969	4.782	4.833	4.429	3.955	3.549	2.797	1.987	1.177
Lower 48 Deep	1.555	1.705	1.826	2.326	2.025	3.016	3.423	3.448	2.650	1.032
Alaskan	0.232	0.241	0.235	0.233	0.233	1.456	1.564	1.588	1.581	1.573
Lurgi Coal Gas	0.000	0.000	0.000	0.000	0.001	0.023	0.424	2.481	6.202	10.002
Total	17.317	18.090	18.094	18.531	18.220	18.119	18.004	17.940	18.032	18.123

Table #7.21: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.19	3.72	4.36	4.92	5.44	6.07	6.66	6.57	7.55
Rocky Mountains	2.86	3.39	3.91	4.44	4.97	5.49	5.95	6.08	6.28
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	10.05	7.31	6.42	6.12
Anadarko	3.42	4.07	4.70	5.37	6.05	6.86	7.58	7.87	8.46
West Texas	3.47	4.18	4.75	5.46	6.23	7.02	7.23	7.87	7.84
Gulf Coast	3.51	4.15	4.81	5.52	6.27	7.11	7.91	8.12	8.65
Midwest	4.26	4.99	5.76	6.53	7.43	8.36	8.78	8.83	8.70
Appalachian	3.52	4.25	4.95	5.81	6.68	7.68	8.45	8.50	8.50
Average	3.41	4.02	4.65	5.32	6.01	6.75	7.32	7.23	7.11

8. SENSITIVITY CASE: TOUT

Table H8.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports to U.S.
1985	2.807	1.800	0.900
1990	3.801	2.330	1.402
1995	3.743	2.449	1.147
2000	3.896	2.630	1.111
2005	4.255	2.809	1.194
2010	4.450	3.176	1.091
2015	4.910	3.381	1.274
2020	4.904	3.571	1.054
2025	4.435	3.726	0.743
2030	3.965	3.881	0.431

Table H8.2: Summary Results for the .S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.361	16.177	0.900	0.056	0.000
1990	17.361	17.649	1.402	0.039	0.010
1995	16.656	16.886	1.147	0.060	0.102
2000	17.022	17.296	1.111	0.084	0.154
2005	16.325	17.020	1.194	0.121	0.405
2010	16.004	16.892	1.091	0.149	0.606
2015	15.644	16.775	1.274	0.272	0.608
2020	15.969	16.710	1.054	0.161	0.604
2025	16.952	16.664	0.743	0.102	0.421
2030	17.954	16.618	0.431	0.043	0.237

Table H8.3: Western Canadian Sectoral Demand
Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.260	0.190	0.500	0.950
1990	0.309	0.255	0.612	1.176
1995	0.321	0.289	0.592	1.202
2000	0.335	0.314	0.622	1.271
2005	0.360	0.340	0.666	1.366
2010	0.356	0.396	0.719	1.471
2015	0.374	0.423	0.749	1.546
2020	0.381	0.450	0.781	1.612
2025	0.390	0.477	0.778	1.645
2030	0.399	0.503	0.775	1.677

Table H8.4: Western Canadian Sectoral Demand
Burnertip Prices ($1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	5.24	4.52	3.85	4.36
1995	6.09	5.37	4.72	5.24
2000	6.74	6.02	5.38	5.90
2005	7.42	6.70	6.07	6.58
2010	8.21	7.49	6.88	7.37
2015	9.03	8.31	7.72	8.20
2020	10.53	9.81	9.24	9.70
2025	11.89	11.17	10.63	11.09
2030	14.92	14.20	13.72	14.15

Table H8.5: Ontario and Eastern Canadian Sectoral Demand Quantities (quadrillion BTU's)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Total	Total
1985	0.190	0.180	0.300	0.670	0.180
1990	0.236	0.258	0.383	0.877	0.277
1995	0.249	0.281	0.398	0.928	0.320
2000	0.254	0.316	0.429	0.999	0.360
2005	0.261	0.362	0.476	1.099	0.424
2010	0.278	0.417	0.520	1.215	0.489
2015	0.286	0.454	0.549	1.289	0.546
2020	0.294	0.491	0.583	1.368	0.592
2025	0.301	0.529	0.609	1.439	0.644
2030	0.308	0.567	0.634	1.509	0.696

Table H8.6: Ontario and Eastern Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Average Price	Average Price
1990	6.34	5.32	4.76	5.35	5.13
1995	7.26	6.24	5.69	6.28	6.05
2000	7.94	6.92	6.38	6.95	6.71
2005	8.64	7.62	7.09	7.63	7.39
2010	9.46	8.44	7.93	8.46	8.21
2015	10.29	9.27	8.77	9.28	9.02
2020	11.82	10.80	10.32	10.81	10.53
2025	13.18	12.16	11.71	12.18	11.90
2030	15.14	14.12	13.70	14.15	15.02

Table H8.7: Canadian Exports by U.S Demand Region Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1985	0.510	0.000	0.390	0.000	0.900
1990	0.573	0.141	0.429	0.259	1.402
1995	0.433	0.159	0.309	0.246	1.147
2000	0.357	0.163	0.296	0.294	1.110
2005	0.304	0.164	0.336	0.389	1.193
2010	0.232	0.147	0.204	0.506	1.089
2015	0.171	0.111	0.235	0.755	1.272
2020	0.104	0.067	0.157	0.724	1.052
2025	0.070	0.045	0.122	0.505	0.742
2030	0.036	0.023	0.086	0.286	0.431

Table H8.8: Canadian Exports by U.S Demand Region Delivered Prices ($1987 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	4.07	4.10	4.80	5.09	4.48
1995	4.88	4.84	5.72	6.03	5.35
2000	5.51	5.47	6.38	6.70	6.05
2005	6.19	6.15	7.06	7.40	6.82
2010	6.93	6.88	7.87	8.22	7.70
2015	7.77	7.74	8.68	9.00	8.67
2020	9.25	9.20	9.89	9.98	9.84
2025	10.57	10.53	11.08	11.18	11.07
2030	13.67	13.65	14.29	14.55	14.38

Table H8.9: Competing Gas Sources in the Pacific Region
Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.004	0.551	0.827	0.362	0.573	2.317
1995	0.026	0.649	1.070	0.243	0.433	2.422
2000	0.040	0.648	1.303	0.168	0.357	2.516
2005	0.051	0.647	1.393	0.113	0.304	2.511
2010	0.048	0.622	1.348	0.071	0.232	2.346
2015	0.055	0.577	1.431	0.047	0.171	2.299
2020	0.034	0.508	1.564	0.034	0.104	2.262
2025	0.023	0.391	1.678	0.039	0.070	2.228
2030	0.012	0.274	1.792	0.043	0.036	2.193

Table H8.10: Competing Gas Sources in the Pacific Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.74	3.95	3.86	4.49	4.07	4.03
1995	5.10	4.58	4.45	5.19	4.88	4.70
2000	5.79	5.24	5.02	5.90	5.51	5.26
2005	6.42	5.84	5.62	6.66	6.19	5.84
2010	7.14	6.39	6.17	7.47	6.93	6.39
2015	7.71	7.06	6.71	8.34	7.77	6.91
2020	9.33	7.65	7.15	8.85	9.25	7.46
2025	10.42	7.94	7.25	8.72	10.57	7.57
2030	11.94	8.52	7.39	8.68	13.67	7.56

Table H8.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	1.077	0.000	0.505	0.106	0.141	1.831
1995	1.146	0.000	0.303	0.091	0.159	1.699
2000	1.160	0.000	0.188	0.075	0.163	1.587
2005	1.134	0.000	0.121	0.060	0.164	1.478
2010	1.144	0.000	0.080	0.046	0.147	1.417
2015	1.186	0.000	0.052	0.033	0.111	1.383
2020	1.198	0.027	0.034	0.026	0.067	1.351
2025	0.979	0.250	0.023	0.024	0.045	1.320
2030	0.760	0.472	0.012	0.022	0.023	1.289

Table H8.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.86	0.00	4.38	4.35	4.10	4.05
1995	4.45	0.00	5.08	5.02	4.84	4.63
2000	5.01	0.00	5.76	5.71	5.47	5.18
2005	5.61	0.00	6.48	6.45	6.15	5.78
2010	6.16	0.00	7.24	7.24	6.88	6.33
2015	6.70	8.98	8.13	8.07	7.74	6.87
2020	7.13	8.06	8.87	8.56	9.20	7.33
2025	7.23	7.41	9.13	8.44	10.53	7.43
2030	7.37	7.12	9.63	8.40	13.65	7.43

Table H8.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.686
1990	0.000	0.000	1.630	1.642	0.093	0.429	3.794
1995	0.000	0.000	1.412	1.456	0.069	0.309	3.245
2000	0.000	0.000	1.310	1.333	0.055	0.296	2.993
2005	0.000	0.000	1.201	1.187	0.047	0.336	2.770
2010	1.121	0.000	0.724	0.715	0.028	0.204	2.792
2015	1.207	0.014	0.626	0.587	0.025	0.235	2.693
2020	1.221	0.447	0.453	0.407	0.023	0.157	2.708
2025	1.211	1.420	0.356	0.321	0.020	0.122	3.449
2030	1.200	2.393	0.258	0.235	0.017	0.086	4.189

Table H8.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Average Price
1990	0.00	0.00	4.53	4.53	5.26	4.60	4.58
1995	0.00	0.00	5.24	5.22	6.06	5.72	5.30
2000	0.00	0.00	5.94	5.94	6.90	6.38	6.00
2005	0.00	14.36	6.68	6.70	7.75	7.06	6.76
2010	5.98	11.01	7.45	7.51	8.70	7.87	6.92
2015	8.03	9.36	8.36	8.42	9.61	8.68	8.27
2020	8.38	8.40	9.12	9.25	10.03	9.89	8.74
2025	8.05	7.73	9.39	9.37	10.07	11.08	8.30
2030	8.07	7.43	9.90	9.57	9.82	14.29	8.04

Table H8.15: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.798	0.376	0.010	0.259	2.441
1995	1.783	0.232	0.091	0.246	2.353
2000	1.849	0.166	0.135	0.294	2.444
2005	1.597	0.128	0.348	0.389	2.463
2010	1.364	0.243	0.510	0.506	2.624
2015	1.162	0.228	0.507	0.755	2.653
2020	1.167	0.310	0.500	0.724	2.700
2025	1.132	0.764	0.349	0.505	2.749
2030	1.097	1.217	0.197	0.286	2.797

Table H8.16: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.86	5.69	5.73	5.09	5.02
1995	5.51	6.46	5.94	6.03	5.67
2000	6.22	7.21	6.73	6.70	6.37
2005	7.10	8.00	7.21	7.40	7.21
2010	8.05	8.31	8.04	8.22	8.10
2015	9.02	9.59	9.18	9.00	9.09
2020	9.68	10.10	10.00	9.98	9.87
2025	9.69	9.70	11.12	11.18	10.15
2030	9.77	9.44	12.51	14.55	10.31

Table H8.17: Domestic Production by Region
(quadrillion BTU's)

Year	Alberta Conventional	'Tight' Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.807
1990	3.338	0.000	0.471	0.071	0.000	0.000	3.880
1995	2.937	0.021	0.668	0.117	0.000	0.000	3.743
2000	3.086	0.027	0.645	0.135	0.000	0.002	3.895
2005	3.431	0.032	0.646	0.129	0.001	0.015	4.254
2010	3.513	0.047	0.665	0.116	0.051	0.066	4.458
2015	3.210	0.058	0.598	0.087	0.557	0.400	4.910
2020	2.574	0.117	0.577	0.105	0.664	0.865	4.902
2025	2.238	0.174	0.557	0.110	0.691	0.665	4.434
2030	1.902	0.230	0.537	0.115	0.717	0.465	3.966

Table H8.18: Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

Year	Alberta Conventional	'Tight' Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Average Price
1990	3.24	0.00	3.58	3.83	0.00	10.92	3.29
1995	4.13	0.00	4.30	4.64	7.53	7.96	4.15
2000	4.78	0.00	4.91	5.40	6.29	6.54	4.79
2005	5.44	0.00	5.57	6.25	5.63	6.04	5.45
2010	6.24	0.00	6.28	7.22	5.62	6.64	6.20
2015	7.07	0.00	7.11	8.41	5.84	7.23	6.89
2020	8.55	0.00	8.54	9.84	5.87	7.99	7.91
2025	9.88	0.00	9.82	11.10	5.88	9.11	8.78
2030	12.89	0.00	12.87	13.96	6.03	12.20	10.85

Table H8.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.358	0.579	0.682	0.681	0.680	0.654	0.607	0.534	0.411	0.288
Rocky Mountains	1.504	2.070	2.409	2.679	2.747	2.709	2.854	3.217	3.308	3.398
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.430	2.323	4.217
Andarko	2.829	2.718	2.381	2.337	2.319	1.967	1.890	1.571	1.129	0.686
West Texas	1.478	1.506	1.369	1.392	1.281	1.166	1.347	2.191	3.084	3.977
Gulf Coast	9.406	9.035	8.045	7.930	7.495	6.792	6.247	5.139	3.599	2.059
Midwest	0.123	0.133	0.118	0.108	0.102	0.085	0.089	0.155	0.308	0.460
Appalachian	0.431	1.081	1.416	1.663	1.469	1.225	1.027	1.121	1.204	1.287
Total Lower 48	16.129	17.122	16.420	16.790	16.093	14.590	14.069	14.358	15.365	16.372
South Alaska	0.232	0.241	0.235	0.233	0.233	0.233	0.233	0.218	0.182	0.145
North Alaska	0.000	0.000	0.000	0.000	0.000	1.254	1.342	1.374	1.405	1.435
Total U.S	17.317	18.812	17.965	18.371	18.045	17.930	17.798	17.768	18.217	18.665

Table H8.20 U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.860	10.400	9.750	9.504	8.623	7.348	6.341	5.163	3.732	2.301
Lower 48 Offshore	4.713	4.997	4.817	4.901	4.518	4.054	3.595	2.771	1.943	1.114
Lower 48 Deep	1.555	1.724	1.853	2.385	2.951	3.161	3.559	3.460	2.608	1.756
Alaskan	0.232	0.241	0.235	0.233	0.233	1.487	1.575	1.592	1.586	1.580
Luigi Coal Gas	0.000	0.000	0.000	0.000	0.001	0.034	0.574	2.953	7.065	11.176
Total	17.317	18.812	17.965	18.371	18.045	17.930	17.798	17.768	18.217	18.665

Table H8.21: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.22	3.82	4.47	5.05	5.58	6.24	6.81	7.09	7.65
Rocky Mountains	2.93	3.48	4.01	4.58	5.10	5.63	6.05	6.12	6.20
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	9.74	7.26	6.41	6.11
Andarko	3.49	4.15	4.80	5.49	6.20	7.03	7.73	7.99	8.55
West Texas	3.52	4.17	4.83	5.57	6.36	7.13	7.27	7.08	7.04
Gulf Coast	3.57	4.22	4.90	5.63	6.40	7.27	8.04	8.20	8.71
Midwest	4.32	5.08	5.88	6.68	7.62	8.53	8.87	8.91	8.66
Appalachian	3.63	4.38	5.12	6.03	6.98	8.01	8.58	8.52	8.55
Average	3.47	4.10	4.75	5.44	6.15	6.91	7.42	7.25	7.07

9. SENSITIVITY CASE: EASTUF

Table H9.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports to U.S.
1985	2.807	1.800	0.900
1990	4.067	2.350	1.561
1995	3.965	2.482	1.330
2000	4.194	2.675	1.355
2005	4.664	2.947	1.532
2010	4.922	3.259	1.457
2015	5.278	3.456	1.567
2020	5.177	3.676	1.225
2025	4.933	3.940	0.883
2030	4.688	4.203	0.540

Table H9.2: Summary Results for the U.S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.361	16.177	0.900	0.056	0.000
1990	17.242	17.698	1.561	0.038	0.010
1995	16.544	16.962	1.330	0.055	0.101
2000	16.871	17.392	1.355	0.074	0.152
2005	16.096	17.130	1.532	0.105	0.400
2010	15.880	17.016	1.457	0.130	0.559
2015	15.487	16.894	1.567	0.239	0.603
2020	15.917	16.800	1.225	0.143	0.559
2025	16.752	16.739	0.883	0.091	0.397
2030	17.587	16.677	0.540	0.036	0.235

Table H9.3: Western Canadian Sectoral Demand
Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.260	0.190	0.500	0.950
1990	0.310	0.256	0.622	1.188
1995	0.323	0.291	0.605	1.219
2000	0.338	0.318	0.639	1.295
2005	0.365	0.345	0.687	1.397
2010	0.363	0.403	0.748	1.514
2015	0.381	0.431	0.771	1.583
2020	0.390	0.459	0.814	1.663
2025	0.405	0.495	0.851	1.752
2030	0.421	0.531	0.888	1.840

Table H9.4: Western Canadian Sectoral Demand
Burnertip Prices ($1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	5.14	4.42	3.75	3.63
1995	5.95	5.23	4.57	5.01
2000	6.55	5.83	5.18	5.44
2005	7.17	6.45	5.81	6.00
2010	7.83	7.11	6.49	6.44
2015	8.81	8.09	7.48	7.71
2020	9.95	9.23	8.65	8.73
2025	10.71	9.99	9.42	9.48
2030	12.31	11.59	11.06	11.05

Table H9.5: Ontario and Eastern Canadian Sectoral Demand Quantities (quadrillion BTU's)

		ONTARIO			EASTERN CANADA
Year	Residential	Commercial	Industrial	Total	Total
1985	0.190	0.180	0.300	0.670	0.180
1990	0.237	0.259	0.388	0.884	0.279
1995	0.251	0.283	0.405	0.939	0.323
2000	0.257	0.319	0.440	1.016	0.366
2005	0.264	0.366	0.488	1.118	0.432
2010	0.283	0.424	0.539	1.246	0.500
2015	0.291	0.461	0.564	1.316	0.557
2020	0.300	0.500	0.606	1.406	0.607
2025	0.310	0.546	0.6505	1.507	0.681
2030	0.321	0.591	0.695	1.607	0.755

Table H9.6: Ontario and Eastern Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

		ONTARIO			EASTERN CANADA
Year	Residential	Commercial	Industrial	Average Price	Average Price
1990	6.24	5.22	4.65	5.24	5.03
1995	7.11	6.09	5.53	6.12	5.89
2000	7.74	6.72	6.17	6.74	6.51
2005	8.39	7.37	6.84	7.38	7.14
2010	9.07	8.05	7.53	8.06	7.81
2015	10.07	9.05	8.54	9.06	8.81
2020	11.20	10.18	9.70	10.19	9.95
2025	11.98	10.96	10.49	10.97	10.69
2030	13.46	12.44	11.99	12.45	12.21

Table H9.7: Canadian Exports by U.S Demand Region Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1985	0.510	0.000	0.390	0.000	0.900
1990	0.611	0.167	0.478	0.304	1.560
1995	0.476	0.191	0.365	0.297	1.329
2000	0.411	0.202	0.374	0.366	1.353
2005	0.375	0.217	0.446	0.491	1.529
2010	0.308	0.209	0.268	0.669	1.454
2015	0.227	0.157	0.295	0.886	1.565
2020	0.140	0.095	0.199	0.790	1.224
2025	0.095	0.064	0.151	0.573	0.882
2030	0.049	0.032	0.103	0.356	0.540

Table H9.8: Canadian Exports by U.S Demand Region Delivered Prices ($1987 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	3.97	4.01	4.70	4.98	4.39
1995	4.76	4.73	5.56	5.87	5.22
2000	5.35	5.32	6.17	6.50	5.88
2005	5.95	5.91	6.81	7.15	6.50
2010	6.59	6.54	7.48	7.84	7.32
2015	7.53	7.49	8.48	8.86	8.46
2020	8.73	8.70	9.60	9.93	9.64
2025	9.47	9.45	10.15	10.25	10.09
2030	11.17	11.25	11.37	11.49	11.42

Table H9.9: Competing Gas Sources in the Pacific Region
Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.004	0.541	0.809	0.362	0.611	2.327
1995	0.023	0.641	1.055	0.242	0.476	2.437
2000	0.034	0.639	1.283	0.166	0.411	2.535
2005	0.043	0.632	1.367	0.111	0.375	2.532
2010	0.041	0.608	1.318	0.070	0.308	2.366
2015	0.046	0.571	1.410	0.046	0.227	2.317
2020	0.029	0.510	1.548	0.033	0.140	2.277
2025	0.020	0.396	1.665	0.037	0.095	2.239
2030	0.010	0.282	1.781	0.041	0.049	2.200

Table H9.10: Competing Gas Sources in the Pacific Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.74	3.91	3.81	4.46	3.97	3.98
1995	5.10	4.52	4.40	5.15	4.76	4.64
2000	5.79	5.18	4.96	5.85	5.35	5.19
2005	6.42	5.77	5.54	6.61	5.95	5.74
2010	7.14	6.31	6.09	7.40	6.59	6.28
2015	7.71	6.97	6.63	8.26	7.53	6.84
2020	9.33	7.57	7.10	8.81	8.73	7.40
2025	10.42	7.87	7.22	8.71	9.47	7.51
2030	11.94	8.46	7.39	8.69	11.17	7.53

Table H9.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	1.060	0.000	0.504	0.106	0.167	1.837
1995	1.128	0.000	0.302	0.088	0.191	1.708
2000	1.137	0.000	0.187	0.071	0.202	1.597
2005	1.098	0.000	0.118	0.056	0.217	1.490
2010	1.100	0.000	0.078	0.042	0.209	1.429
2015	1.154	0.000	0.051	0.031	0.157	1.393
2020	1.182	0.024	0.033	0.024	0.095	0.136
2025	0.972	0.244	0.023	0.023	0.064	0.713
2030	0.762	0.463	0.012	0.021	0.032	1.290

Table H9.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.82	0.00	4.35	4.32	4.01	4.01
1995	4.40	0.00	5.03	4.99	4.73	4.58
2000	4.95	0.00	5.70	5.67	5.32	5.12
2005	5.54	0.00	6.42	6.40	5.91	5.69
2010	6.08	0.00	7.16	7.17	6.54	6.24
2015	6.62	8.95	8.04	8.00	7.49	6.80
2020	7.08	8.06	8.79	8.53	8.70	72.78
2025	7.21	7.42	9.07	8.43	9.45	13.76
2030	7.37	7.13	9.59	8.41	11.25	7.42

Table H9.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.686
1990	0.000	0.000	1.615	1.617	0.093	0.478	3.803
1995	0.000	0.000	1.398	1.426	0.068	0.365	3.256
2000	0.000	0.000	1.287	1.290	0.054	0.374	3.005
2005	0.000	0.000	1.160	1.130	0.045	0.446	2.780
2010	1.109	0.000	0.691	0.672	0.027	0.268	2.768
2015	1.205	0.012	0.595	0.550	0.023	0.295	2.680
2020	1.221	0.428	0.441	0.389	0.023	0.199	2.701
2025	1.209	1.291	0.339	0.301	0.019	0.151	3.310
2030	1.197	2.155	0.236	0.212	0.015	0.103	3.919

Table H9.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Average Price
1990	0.00	0.00	4.50	4.50	5.22	4.70	4.54
1995	0.00	0.00	5.20	5.19	6.01	5.56	5.25
2000	0.00	0.00	5.89	5.89	6.84	6.17	5.94
2005	0.00	14.29	6.62	6.64	7.67	6.81	6.68
2010	5.89	10.95	7.37	7.45	8.61	7.48	6.82
2015	7.92	9.32	8.27	8.34	9.52	8.48	8.17
2020	8.35	8.40	9.04	9.18	9.99	9.60	8.70
2025	7.99	7.74	9.33	9.33	10.04	10.15	8.26
2030	7.94	7.44	9.86	9.56	9.85	11.37	7.96

Table H9.15: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.761	0.375	0.009	0.304	2.450
1995	1.748	0.231	0.090	0.297	2.366
2000	1.800	0.163	0.133	0.366	2.462
2005	1.532	0.123	0.340	0.491	2.485
2010	1.289	0.204	0.493	0.669	2.654
2015	1.103	0.199	0.493	0.886	2.681
2020	1.144	0.292	0.493	0.790	2.718
2025	1.097	0.761	0.343	0.573	2.774
2030	1.050	1.229	0.193	0.356	2.829

Table H9.16: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.82	5.64	6.03	4.98	4.97
1995	5.44	6.41	6.18	5.87	5.62
2000	6.13	7.14	6.99	6.50	6.30
2005	6.99	7.91	7.34	7.15	7.12
2010	7.88	8.20	8.05	7.84	7.93
2015	8.91	9.48	9.33	8.86	9.01
2020	9.63	10.06	10.20	9.93	9.87
2025	9.66	9.66	11.12	10.25	9.96
2030	9.77	9.38	12.91	11.49	10.00

Table H9.17: Domestic Production by Region
(quadrillion BTU's)

Year	Alberta Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.807
1990	3.510	0.000	0.483	0.073	0.000	0.000	4.066
1995	3.058	0.100	0.687	0.120	0.000	0.000	3.965
2000	3.235	0.132	0.685	0.140	0.000	0.003	4.195
2005	3.615	0.164	0.746	0.133	0.000	0.006	4.664
2010	3.767	0.236	0.763	0.115	0.022	0.020	4.923
2015	3.510	0.329	0.709	0.098	0.421	0.211	5.278
2020	2.647	0.689	0.586	0.115	0.657	0.483	5.177
2025	2.128	0.999	0.506	0.106	0.673	0.522	4.932
2030	1.600	1.309	0.426	0.096	0.688	0.568	4.687

Table H9.18: Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

Year	Alberta Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Average Price
1990	3.14	4.50	3.49	3.71	0.00	11.56	3.19
1995	3.99	4.38	4.19	4.48	7.56	8.60	4.02
2000	4.57	5.11	4.76	5.18	6.21	7.11	4.64
2005	5.19	5.79	5.33	5.98	5.52	6.51	5.26
2010	5.85	6.42	5.95	6.86	5.44	6.76	5.92
2015	6.86	7.29	6.87	7.94	5.68	7.66	6.91
2020	8.02	8.13	8.05	9.02	5.76	8.07	7.87
2025	8.69	9.02	8.77	10.01	5.75	8.26	8.36
2030	10.50	10.07	10.57	11.85	5.87	9.39	9.70

Table H9.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.358	0.569	0.674	0.672	0.665	0.639	0.601	0.536	0.417	0.297
Rocky Mountains	1.504	2.032	2.372	2.631	2.679	2.627	2.796	3.178	3.273	3.368
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.007	0.401	2.168	3.934
Andarko	2.829	2.703	2.370	2.321	2.283	1.945	1.879	1.586	1.144	0.702
West Texas	1.478	1.500	1.362	1.305	1.271	1.158	1.318	2.144	3.032	3.920
Gulf Coast	9.406	9.003	8.013	7.877	7.418	6.705	6.216	5.172	3.641	2.109
Midwest	0.123	0.132	0.118	0.108	0.101	0.084	0.087	0.149	0.293	0.437
Appalachian	0.431	1.063	1.399	1.643	1.446	1.210	1.013	1.119	1.182	1.244
Total Lower 48	16.129	17.002	16.308	16.637	15.863	14.368	13.917	14.285	15.148	16.011
South Alaska	0.232	0.241	0.235	0.233	0.233	0.233	0.233	0.218	0.182	0.145
North Alaska	0.000	0.000	0.000	0.000	0.000	1.238	1.339	1.374	1.403	1.432
Total U.S	17.317	18.851	18.030	18.452	18.133	18.026	17.896	17.844	18.122	18.400

Table H9.20: U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.860	10.316	9.678	9.420	8.506	7.259	6.321	5.230	3.793	2.356
Lower 48 Offshore	4.713	4.975	4.795	4.865	4.472	3.999	3.587	2.795	1.969	1.142
Lower 48 Deep	1.555	1.711	1.837	2.352	2.884	3.083	3.503	3.473	2.636	1.799
Alaskan	0.232	0.241	0.235	0.233	0.233	1.471	1.571	1.591	1.584	1.577
Lurgi Coal Gas	0.000	0.000	0.000	0.000	0.001	0.028	0.505	2.778	6.734	10.689
Total	17.317	18.851	18.030	18.452	18.133	18.026	17.896	17.844	18.122	18.400

Table H9.21: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.18	3.77	4.41	4.98	5.51	6.15	6.73	7.02	7.59
Rocky Mountains	2.89	3.43	3.96	4.51	5.03	5.55	6.00	6.10	6.20
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	9.87	7.29	6.41	6.12
Andarko	3.45	4.11	4.75	5.43	6.12	6.95	7.66	7.93	8.50
West Texas	3.49	4.14	4.79	5.52	6.29	7.08	7.25	7.08	7.04
Gulf Coast	3.54	4.19	4.85	5.57	6.34	7.19	7.98	8.17	8.68
Midwest	4.29	5.03	5.82	6.61	7.53	8.45	8.83	8.86	8.68
Appalachian	3.57	4.31	5.03	5.91	6.80	7.89	8.55	8.50	8.55
Average	3.44	4.06	4.70	5.38	6.08	6.83	7.38	7.24	7.89

10. SENSITIVITY CASE: MEXUP

Table H10.1: Summary Results for Canada (Quadrillion BTUs)

Year	Production	Demand	Exports to U.S.
1985	2.807	1.800	0.900
1990	4.063	2.355	1.552
1995	3.961	2.439	1.318
2000	4.183	2.684	1.335
2005	4.650	2.960	1.504
2010	4.903	3.272	1.424
2015	5.395	3.489	1.641
2020	5.321	3.706	1.322
2025	4.994	3.949	0.934
2030	4.666	4.191	0.546

Table H10.2: Summary Results for the U.S. (Quadrillion BTUs)

Year	Production	Demand	Canadian Imports	Mexican Imports	LNG Imports
1985	16.361	16.177	0.900	0.056	0.002
1990	17.283	17.735	1.552	0.046	0.010
1995	16.587	17.022	1.318	0.088	0.102
2000	16.864	17.471	1.335	0.187	0.153
2005	15.994	17.225	1.504	0.338	0.403
2010	15.651	17.122	1.424	0.472	0.601
2015	15.130	17.029	1.641	0.669	0.603
2020	15.445	16.935	1.322	0.624	0.600
2025	16.450	16.810	0.934	0.404	0.416
2030	17.456	16.684	0.546	0.184	0.232

Table H10.3: Western Canadian Sectoral Demand
Quantities (quadrillion BTU's)

Year	Residential	Commercial	Industrial	Total
1985	0.260	0.190	0.500	0.950
1990	0.310	0.257	0.624	1.191
1995	0.323	0.292	0.609	1.224
2000	0.339	0.318	0.642	1.299
2005	0.366	0.346	0.692	1.404
2010	0.364	0.404	0.752	1.520
2015	0.383	0.433	0.783	1.599
2020	0.392	0.463	0.823	1.678
2025	0.407	0.497	0.853	1.757
2030	0.421	0.532	0.882	1.835

Table H10.4: Western Canadian Sectoral Demand
Burnertip Prices ($1985 U.S per MMBTU)

Year	Residential	Commercial	Industrial	Average
1990	5.12	4.40	3.72	3.60
1995	5.92	5.20	4.54	4.97
2000	6.51	5.79	5.14	5.41
2005	7.12	6.40	5.76	5.94
2010	7.79	7.07	6.45	6.41
2015	8.61	7.89	7.28	7.48
2020	9.87	9.15	8.56	8.66
2025	10.77	10.05	9.48	9.58
2030	12.43	11.71	11.18	11.22

Table H10.5: Ontario and Eastern Canadian Sectoral Demand Quantities (quadrillion BTU's)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Total	Total
1985	0.190	0.180	0.300	0.670	0.180
1990	0.237	0.259	0.309	0.805	0.279
1995	0.252	0.283	0.407	0.942	0.324
2000	0.258	0.319	0.442	1.019	0.367
2005	0.265	0.367	0.491	1.123	0.434
2010	0.284	0.425	0.541	1.250	0.502
2015	0.292	0.464	0.572	1.328	0.562
2020	0.302	0.503	0.612	1.417	0.612
2025	0.311	0.548	0.6515	1.511	0.682
2030	0.321	0.592	0.691	1.604	0.751

Table H10.6: Ontario and Eastern Canadian Sectoral Demand Burnertip Prices ($1985 U.S per MMBTU)

	ONTARIO				EASTERN CANADA
Year	Residential	Commercial	Industrial	Average Price	Average Price
1990	6.22	5.20	4.63	5.22	5.00
1995	7.00	6.06	5.50	6.09	5.86
2000	7.70	6.60	6.13	6.70	6.47
2005	8.33	7.31	6.78	7.32	7.09
2010	9.03	8.01	7.49	8.02	7.78
2015	9.96	8.84	8.33	8.94	8.60
2020	11.11	10.09	9.61	10.10	9.86
2025	12.05	11.03	10.56	11.04	10.00
2030	13.57	12.55	12.11	12.56	12.47

Table H10.7: Canadian Exports by U.S Demand Region Delivered Quantities (quadrillion BTU's)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Total
1985	0.510	0.000	0.390	0.000	0.900
1990	0.607	0.166	0.475	0.302	1.550
1995	0.471	0.189	0.361	0.296	1.317
2000	0.400	0.201	0.369	0.363	1.333
2005	0.357	0.214	0.440	0.490	1.501
2010	0.209	0.285	0.265	0.663	1.422
2015	0.218	0.158	0.307	0.955	1.638
2020	0.134	0.096	0.208	0.883	1.321
2025	0.09	0.064	0.1575	0.6215	0.933
2030	0.046	0.032	0.107	0.360	0.545

Table H10.8: Canadian Exports by U.S Demand Region Delivered Prices ($1987 U.S per MMBTU)

Year	Pacific	W.N Central/ Mountain	E.N Central	Mid-Atlantic/ New England	Average Price
1990	3.94	3.99	4.67	4.96	4.37
1995	4.73	4.70	5.53	5.84	5.19
2000	5.31	5.28	6.14	6.46	5.85
2005	5.69	5.85	6.75	7.09	6.53
2010	6.54	6.50	7.44	7.79	7.28
2015	7.35	7.31	8.25	8.54	8.21
2020	8.65	8.62	9.48	9.70	9.48
2025	9.51	9.47	10.37	10.56	10.35
2030	11.29	11.35	11.96	12.23	12.05

Table H10.9: Competing Gas Sources in the Pacific Region
Delivered Quantities (quadrillion BTU's)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Total
1985	0.000	0.340	0.431	0.429	0.510	1.710
1990	0.009	0.544	0.808	0.362	0.608	2.332
1995	0.044	0.543	1.046	0.242	0.471	2.447
2000	0.096	0.636	1.250	0.165	0.400	2.548
2005	0.149	0.619	1.310	0.110	0.357	2.548
2010	0.160	0.593	1.253	0.068	0.289	2.382
2015	0.162	0.561	1.335	0.045	0.218	2.333
2020	0.129	0.507	1.474	0.032	0.134	2.291
2025	0.0885	0.3985	1.6075	0.036	0.09	2.2455
2030	0.048	0.290	1.741	0.040	0.046	2.200

Table H10.10: Competing Gas Sources in the Pacific Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Mexico	From Pacific	From Rocky Mtns	From West Texas	From Canada	Average Price
1990	4.48	3.88	3.79	4.42	3.94	3.95
1995	4.89	4.48	4.37	5.11	4.73	4.60
2000	5.37	5.12	4.91	5.80	5.31	5.14
2005	5.90	5.70	5.48	6.54	5.89	5.68
2010	6.51	6.24	6.03	7.31	6.54	6.23
2015	7.19	6.87	6.57	8.15	7.35	6.77
2020	7.96	7.48	7.04	8.75	8.65	7.36
2025	8.84	7.80	7.20	8.71	9.51	7.53
2030	9.83	8.40	7.39	8.71	11.29	7.56

Table H10.11: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Quantities (quadrillion BTU's)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Total
1985	0.953	0.000	0.850	0.134	0.000	1.937
1990	1.064	0.000	0.505	0.106	0.166	1.840
1995	1.135	0.000	0.303	0.087	0.189	1.714
2000	1.146	0.000	0.187	0.071	0.201	1.604
2005	1.110	0.000	0.118	0.055	0.214	1.498
2010	1.112	0.000	0.078	0.042	0.205	1.438
2015	1.162	0.000	0.051	0.031	0.158	1.402
2020	1.191	0.022	0.033	0.024	0.096	1.366
2025	0.981	0.239	0.0225	0.0225	0.064	1.329
2030	0.771	0.456	0.012	0.021	0.032	1.292

Table H10.12: Competing Gas Sources in the W.N Central/Mountain Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Rocky Mtns	From NGP	From Andarko	From West Texas	From Canada	Average Price
1990	3.79	0.00	4.32	4.29	3.99	3.98
1995	4.37	0.00	4.99	4.95	4.70	4.55
2000	4.91	0.00	5.66	5.62	5.28	5.08
2005	5.48	0.00	6.36	6.33	5.85	5.63
2010	6.02	0.00	7.07	7.08	6.50	6.17
2015	6.55	8.92	7.93	7.89	7.31	6.72
2020	7.02	8.06	8.69	8.47	8.62	7.22
2025	7.19	7.43	9.00	8.43	9.47	7.39
2030	7.37	7.14	9.56	8.43	11.35	7.42

Table H10.13: Competing Gas Sources in the E.N Central Region
Delivered Quantities (quadrillion BTU's)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Total
1985	0.000	0.000	1.570	1.609	0.117	0.390	3.686
1990	0.000	0.000	1.618	1.624	0.093	0.475	3.820
1995	0.000	0.000	1.401	1.436	0.068	0.361	3.282
2000	0.000	0.000	1.291	1.304	0.055	0.369	3.033
2005	0.000	0.000	1.161	1.149	0.046	0.440	2.806
2010	1.112	0.000	0.692	0.684	0.027	0.265	2.768
2015	1.202	0.010	0.586	0.558	0.023	0.307	2.671
2020	1.221	0.404	0.439	0.404	0.022	0.208	2.668
2025	1.2095	1.2695	0.3375	0.312	0.0185	0.1575	3.2335
2030	1.198	2.135	0.236	0.220	0.015	0.107	3.799

Table H10.14: Competing Gas Sources in the E.N Central Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From North Alaska	From NGP	From Andarko	From Gulf	From Midwestern	From Canada	Average Price
1990	0.00	0.00	4.47	4.47	5.19	4.67	4.50
1995	0.00	0.00	5.16	5.15	5.96	5.53	5.19
2000	0.00	0.00	5.84	5.84	6.78	6.14	5.87
2005	0.00	14.24	6.55	6.56	7.59	6.75	6.58
2010	5.89	10.90	7.29	7.34	8.51	7.44	6.80
2015	7.78	9.29	8.16	8.19	9.41	8.25	8.07
2020	8.30	8.40	8.94	9.00	9.93	9.48	8.73
2025	8.01	7.75	9.26	9.27	10.04	10.37	8.46
2030	7.98	7.45	9.83	9.57	9.89	11.96	8.24

Table H10.15: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Quantities (quadrillion BTU's)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Total
1985	1.540	0.505	0.000	0.000	2.045
1990	1.766	0.376	0.010	0.302	2.454
1995	1.755	0.232	0.091	0.296	2.373
2000	1.810	0.164	0.134	0.363	2.471
2005	1.540	0.123	0.343	0.490	2.497
2010	1.304	0.203	0.498	0.663	2.668
2015	1.069	0.189	0.493	0.955	2.706
2020	1.095	0.274	0.493	0.883	2.746
2025	1.0745	0.7435	0.3425	0.6215	2.7825
2030	1.054	1.213	0.192	0.360	2.819

Table H10.16: Competing Gas Sources in the Mid-Atlantic/New England Region
Delivered Prices ($1985 U.S per MMBTU)

Year	From Appalachians	From E.N Central	From LNG	From Canada	Average Price
1990	4.79	5.61	5.63	4.96	4.94
1995	5.41	6.37	5.81	5.84	5.58
2000	6.08	7.08	6.56	6.46	6.23
2005	6.93	7.84	6.98	7.09	7.01
2010	7.81	8.14	7.84	7.79	7.84
2015	8.77	9.33	8.83	8.54	8.74
2020	9.55	9.98	9.89	9.70	9.70
2025	9.66	9.69	11.12	10.56	10.05
2030	9.79	9.43	12.51	12.23	10.13

Table H10.17: Domestic Production by Region
(quadrillion BTU's)

	Alberta						
Year	Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Total
1985	2.406	0.000	0.340	0.061	0.000	0.000	2.807
1990	3.507	0.000	0.482	0.073	0.000	0.000	4.062
1995	3.056	0.099	0.686	0.120	0.000	0.000	3.961
2000	3.229	0.131	0.681	0.139	0.000	0.003	4.183
2005	3.616	0.159	0.729	0.132	0.000	0.014	4.650
2010	3.742	0.234	0.748	0.116	0.022	0.040	4.902
2015	3.426	0.279	0.690	0.093	0.323	0.584	5.395
2020	2.567	0.603	0.574	0.108	0.655	0.815	5.322
2025	2.107	0.9855	0.5075	0.104	0.6725	0.6175	4.994
2030	1.647	1.368	0.441	0.100	0.690	0.420	4.666

Table H10.18: Domestic Production by Region
Average Wellhead Prices ($1985 U.S per MMBTU)

	Alberta						Average
Year	Conventional	"Tight" Sands	British Columbia	Saskatchewan	Northern	Eastern Offshore	Price
1985							
1990	3.12	4.47	3.47	3.68	0.00	10.81	3.17
1995	3.96	4.35	4.16	4.45	7.54	7.81	4.02
2000	4.54	5.07	4.72	5.14	6.17	6.35	4.61
2005	5.14	5.75	5.28	5.92	5.48	5.77	5.21
2010	5.81	6.36	5.90	6.79	5.35	6.37	5.88
2015	6.63	7.19	6.70	7.83	5.59	6.76	6.64
2020	7.95	8.06	7.98	8.98	5.72	7.77	7.68
2025	8.77	9.05	8.79	9.98	5.72	8.57	8.42
2030	10.65	10.16	10.66	11.92	5.63	10.11	9.74

Table H10.19: U.S Production of Natural Gas by Region
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48										
Pacific Coast	0.358	0.572	0.676	0.668	0.651	0.624	0.590	0.533	0.419	0.305
Rocky Mountains	1.504	2.035	2.371	2.604	2.630	2.570	2.721	3.097	3.222	3.346
Northern Great Plains	0.000	0.000	0.000	0.000	0.000	0.000	0.006	0.362	2.115	3.868
Andarko	2.829	2.706	2.373	2.319	2.271	1.927	1.848	1.561	1.142	0.723
West Texas	1.478	1.501	1.364	1.385	1.266	1.146	1.267	2.035	2.932	3.829
Gulf Coast	9.406	9.030	8.047	7.896	7.396	6.618	6.075	5.080	3.620	2.159
Midwest	0.123	0.133	0.119	0.109	0.101	0.084	0.085	0.135	0.278	0.420
Appalachian	0.431	1.065	1.404	1.650	1.447	1.213	0.974	1.052	1.141	1.230
Total Lower 48	16.129	17.042	16.354	16.631	15.762	14.182	13.566	13.855	14.868	15.880
South Alaska	0.232	0.241	0.235	0.233	0.233	0.233	0.232	0.217	0.181	0.145
North Alaska	0.000	0.000	0.000	0.000	0.000	1.238	1.334	1.372	1.402	1.431
Total U.S	17.317	18.891	18.095	18.539	18.239	18.148	18.043	17.991	18.205	18.418

Table H10.20: Average U.S Wellhead Price by Region
($1985 U.S per MMBTU)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48									
Pacific Coast	3.15	3.73	4.35	4.91	5.43	6.06	6.64	6.95	7.53
Rocky Mountains	2.86	3.40	3.91	4.45	4.97	5.49	5.95	6.07	6.20
Northern Great Plains	0.00	0.00	0.00	0.00	0.00	10.00	7.31	6.42	6.12
Andarko	3.42	4.07	4.70	5.37	6.04	6.84	7.56	7.86	8.45
West Texas	3.46	4.10	4.74	5.45	6.21	7.00	7.22	7.07	7.03
Gulf Coast	3.51	4.15	4.80	5.50	6.25	7.07	7.85	8.08	8.60
Midwest	4.26	4.99	5.76	6.53	7.43	8.35	8.76	8.83	8.70
Appalachian	3.55	4.28	4.99	5.86	6.74	7.76	8.49	8.50	8.56
Average	3.41	4.03	4.65	5.32	6.00	6.73	7.30	7.21	7.08

Table H10.21: U.S Production of Natural Gas by Technology
(quadrillion BTU's)

	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Onshore	9.860	10.340	9.698	9.413	8.456	7.191	6.213	5.165	3.788	2.410
Lower 48 Offshore	4.713	4.991	4.817	4.874	4.454	3.942	3.511	2.756	1.963	1.169
Lower 48 Deep	1.555	1.711	1.837	2.345	2.851	3.023	3.408	3.407	2.629	1.851
Alaskan	0.232	0.241	0.235	0.233	0.233	1.471	1.566	1.588	1.582	1.576
Lurgi Coal Gas	0.000	0.000	0.000	0.000	0.001	0.024	0.432	2.520	6.473	10.426
Total	17.317	18.891	18.095	18.539	18.239	18.148	18.043	17.991	18.205	18.418

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